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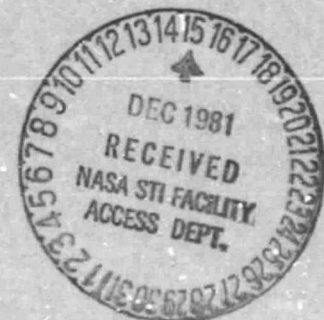
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Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status

M. Hassan
J. Klein



September 15, 1981

Prepared for
U.S. Department of Energy
Through an Agreement with
National Aeronautics and Space Administration
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ABSTRACT

Major technical issues involving the integration of distributed photovoltaics (PV) into electric utility systems are defined and their impacts are described quantitatively. An extensive literature search, interviews, and analysis yielded information about the work in progress and highlighted problem areas in which additional work and research are needed. The findings from the literature search were used to determine whether satisfactory solutions to the problems exist or whether satisfactory approaches to a solution are underway. During this study, it was discovered that very few standards, specifications, or guidelines currently exist that will aid industry in integrating PV into the utility system. Specific areas of concern identified in this study are: (1) protection, (2) stability, (3) system unbalance, (4) voltage regulation and reactive power requirements, (5) harmonics, (6) utility operations, (7) safety, (8) metering, and (9) distribution system planning and design.

FOREWORD

For a smooth integration of dispersed storage and generation (DSG) devices, technical issues of concern must be resolved in a manner satisfactory to all parties. To achieve this goal, coordinated efforts and funding must come from the utilities, manufacturers, and government.

The Electric Energy Systems Division of the Department of Energy (DOE/EES) has been charged with the responsibility of ensuring this smooth integration of DSGs into the utility system. Because of the diversity and characteristics of DSGs, DOE/EES has developed a broad-based generic R&D program for the near-term accommodation and long-term integration of new energy sources into the nation's electric utility systems. This generic program focuses on the effects of integrating new technologies on the power system and changes that must be made in power system planning and operations to ensure successful, long-term integration. Because photovoltaics, batteries, and fuel cells will be connected to the utility similarly, DOE/EES and DOE/PV are funding generic studies in power conditioning development and its effect on the consumer and utility equipment. Also, EES is developing generic methods and tools that incorporate DSGs into utility planning processes and study their effect on system operations.

The individual technologies must also be concerned with the effects of utility characteristics and behavior on the devices and be able to apply the generic tools and results obtained from various sources to their particular technology. For example, control theory development and simulation capability, supported by EES, are used in the PV program to assess the effect of power system behavior on PV system performance and control system stability. Also, DOE/PV uses work conducted and contracted by the field centers and EPRI to gain a better understanding of the issues. With these concerns, this study examines the new technology integration requirements and establishes the effects of various technical issues from a photovoltaics perspective.

The union of these two government efforts (DOE/EES and DOE/PV) with the private sector will increase the likelihood that photovoltaic energy system integration will occur in a smooth and timely way. Because the issues are addressed from several different perspectives, integrating these photovoltaic systems into utilities should be accelerated with fewer difficulties at the time of implementation.

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Many individuals and organizations provided valuable information regarding their respective activities related to this study. The information provided by Southern California Edison and Pasadena Department of Water & Power regarding their distribution practices is gratefully acknowledged. In addition, the proceedings of the Harpers Ferry New Technology Planning Workshop were particularly helpful.

Finally, thanks are due to the editors, Sid Bank and Judie Richey, and staff of the Technical Documentation and Materiel Services Division at JPL.

LIST OF ACRONYMS

AGC	Automatic Generation Control
ANSI	American National Standards Institute
APPA	American Public Power Association
DAC	Distribution Automation and Control
DF	Distortion Factor (Voltage)
DOE	Department of Energy
DSG	Distributed Storage and Generation (Devices)
DSW	Distributed Solar and Wind Systems
EDC	Economic Dispatch Control
EES	Electric Energy Systems (Division of DOE)
EMI	Electro-Magnetic Interference
EPRI	Electric Power Research Institute
FCC	Federal Communications Commission
HVDC	High Voltage Direct Current
IEE	Institute of Electrical Engineers (London)
IEEE	Institute of Electrical and Electronic Engineers
JPL	Jet Propulsion Laboratory
LLP	Large Local Penetration
LTC	Load Tap Changer
LSP	Large System Penetration
METAP	McGraw-Edison Transient Analysis Program
MIT	Massachusetts Institute of Technology
NEC	National Electrical Code
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
ORNL	Oak Ridge National Laboratory

OTEC	Ocean Thermal Energy Conversion
PCS	Power Conditioning Subsystem
PCU	Power Conditioning Unit
PG&E	Pacific Gas and Electric
PUC	Public Utilities Commission
PV	Photovoltaics
QF	Qualifying Facility
RFP	Request for Proposal
SCE	Southern California Edison
SCR	Silicon Controlled Rectifier
SDG&E	San Diego Gas and Electric
T&D	Transmission and Distribution
TNA	Transient Network Analyzer
TOD	Time of Day
TR	Technology Readiness
TVA	Tennessee Valley Authority
VAR	Volt Amperes Reactive
VDE	Verband Deutscher Electrotechniker (West Germany)
WECS	Wind Energy Conversion System

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EXECUTIVE SUMMARY

Photovoltaic (PV) power generation has a great potential for providing a substantial portion of this country's future energy needs. The technology for this clean, abundant source has been available for some time, but the cost of producing PV systems has confined its use to remote areas where costs are high for any energy source. As the costs for PV systems are reduced, they will become more competitive with the present alternatives available to electric utilities. The widespread and significant use of PV that could result from connection of small dispersed PV systems to utility systems gives rise to technical issues not encountered in remote area installations. These issues arise because of the differences between small-size dispersed PV systems and large-size conventional generation and they must be resolved before PV systems can be successfully connected to a utility.

Until now, a limited amount of effort has been devoted to fully understanding and resolving the technical issues of PV integration. There has been even less study devoted to understanding the way PV systems will interact with other Distributed Storage and Generation (DSG) devices such as wind, batteries and fuel cells, that also may be integrated with future utility systems. The U.S. Department of Energy (DOE) PV Program, recognizing the potential problem of unresolved technical issues, commissioned this study to look at these issues, present an overall status report describing the state-of-the-art, and compliment the extensive efforts funded by DOE/EES. During this study, it was realized that very few standards, specifications, or guidelines currently exist that will aid industry in integrating PV into the utility system.

This report defines the major technical issues associated with the integration of distributed PV into electric utility systems and describes their impact quantitatively. The report builds upon the results of the New Technology Integration Planning Workshop held at Harpers Ferry, West Virginia, in August 1980. An extensive literature search, interviews, and analysis yielded information about the work in progress and highlighted problem areas in which additional work and research are needed. The findings of the literature search were used to determine whether satisfactory solutions to the problems exist or whether satisfactory approaches to the solution are underway.

The major areas of concern identified in this study are:

- (1) Protection
- (2) Stability
- (3) System Unbalance
- (4) Voltage Regulation and Reactive Power Requirements
- (5) Harmonics

- (6) Utility Operations
- (7) Safety
- (8) Metering
- (9) Distribution System Planning and Design

The technical issues associated with each of the above areas are defined and their scope, impact and risks are described in this study. No attempt was made to prioritize these issues; it is believed that the successful integration of PV for any given level of penetration requires resolving all the problems associated with that level of penetration.

A. STATUS SUMMARY OF THE VARIOUS ISSUES

The literature review yielded information about the status of the various issues that is summarized in Tables ES-1 and ES-2. Qualitative statements on each issue classified by the risk posed, state of present knowledge, areas of concern and further work needed are summarized in Table ES-1. Based on this summary, a quantitative assessment of the present status of the various issues is presented in Table ES-2. The status of the issues is ranked on a scale of 0 to 10; resolved issues are rated 10; issues totally unresolved are rated 0. The present uncertainty of DOE programs precludes forecasting the future status of these issues. However, analysis of these DOE future activities, as proposed before the budget revisions, does appear in the body of this report.

Table ES-2 also indicates the impact of each issue by the level of PV penetration. The levels of penetration are: (1) Technology Readiness (TR) which for the purposes of this study is defined as the installation of a single PV array connected to the utility system, (2) Large Local Penetration (LLP) which is defined as a level of penetration of PV sources on a distribution feeder when the total PV output is around 10% of the feeder load, and (3) Large System Penetration (LSP) which is defined as a level of penetration of PV sources in any utility system when the total PV output is around 10% of the system load.

B. THE ISSUES

1. Protection

To minimize damage and risk of injury and to assure reliability of service, proper guidelines for overvoltage, overcurrent and over- and under-frequency protection of the power conditioning subsystem (PCS) and the utility system must be established. Because of its complexity, protection is divided into four parts for discussion (Figure ES-1).

a. PCS Overvoltage Protection. The PCS must be protected against transient overvoltages that originate either within the PV system itself or within the utility. If voltage surges are not suppressed, they could damage the electronic components of the PCS.

Table ES-1. Qualitative Summary of the Various Issues

Issue	Risk to Utility Customer, or PV System	State of Present Knowledge	Areas of Concern	Future Work Required
PCS Overvoltage Protection	- Unsuppressed Voltage Surges Could Cause Damage to PCS	- Adequate Understanding of Problems and Potential Solutions	- None	- Specification and Selection of Proper Surge Protection as a Part of PCS
Utility System Overvoltage Protection	- Overvoltages Due to Resonance Could Damage Utility and Customer Equipment	- Theory Behind Resonances Is Well Understood - Preliminary Guidelines to Avoid Resonances with Individual Sources Are Available	- No Guidelines Exist to Avoid Resonances When There Is a Multiplicity of Sources	- Frequency Dependent Models of PV Systems and Utility - Simulation of Representative Distribution Systems with Various Levels of Penetration - Guidelines to Avoid Resonant Conditions with Dispersed PV Systems
PCS Protection (Overcurrent and Others)	- Possibility of Damage to PCS - Adverse Impact on Reliability of Service to Utility Customers	- Specifications for PCS Protection in Conceptual Designs Are Available	- Available Specifications Have Not Been Derived from a Thorough Analysis of Many PV Systems Connected to Utility	- Models of PV Arrays and PCS during Faults - Software for Distribution System Fault Analysis - Simulations of Representative Systems to Determine Protection Requirements
Source Stability	- Nuisance Tripping of PV Source Due to Undesirable Fluctuations in Output - Possibility of Damage to the PV System	- Very Limited Study on Individual Source Stability	- Possibility of Undesirable Response of PCS Control System Including Maximum Power Tracker, Etc., When Connected to a Utility System	- Dynamic Models for PV System - Dynamic Analysis Techniques - Simulations to Determine the Impact on PV Control Systems
Voltage Regulation and Reactive Compensation	- Improper Voltage at Customer's Terminals - Added Cost to PV Owner	- Initial Studies Made to Determine Impact of Distributed PV on Voltage Regulation	- No Standard Definition for Reactive Power Under Non-Sinusoidal Conditions - No Specifications or Guidelines on Amount of Reactive Power Generation or Consumption by PCS - Possibility of Resonances and Self-Excitation if Capacitors Used for Power Factor Correction - Possibility of Voltage Regulator Misoperation	- Survey of Present Distribution System Practices - Steady-State Models for Generic Designs of PCS - Three-phase Distribution Load-Flow Software - Simulations to Determine Modification in Distribution System or PCS Design

Table ES-1. Qualitative Summary of the Various Issues (Contd.)

Issue	Risk to Utility Customers or P.V. System	State of Present Knowledge	Areas of Concern	Future Work Required
Harmonics	<ul style="list-style-type: none"> - Excessive Generation of Harmonics Could Result in Damage to Equipment Connected to Utility - Telephone Interference - Malfunctioning of Relays, Converter Controls Etc. 	<ul style="list-style-type: none"> - Undesirable Effects of Harmonics Fairly Well Known - Limited Guidelines on Allowable Harmonic Limits Available - Some Software Available to Study Harmonic Propagation - Factors for Telephone Interference Well Established 	<ul style="list-style-type: none"> - No Standards for Limits on Voltage/Current Harmonics at the Terminals of PCS. - No Regulations on Conducted and Radiated EMC 	<ul style="list-style-type: none"> - Maximum Tolerable Level of Harmonics for Appliances and Equipment - Background Harmonic Levels on Existing Systems - Improvement in Existing Software to Study Harmonic Propagation - Extensive Simulations to Determine Harmonic Limits
Safety and Code Requirements	<ul style="list-style-type: none"> - Risk of Injury to P.V. Owner and Utility Personnel - Difficulty in Code Approval of P.V. System 	<ul style="list-style-type: none"> - Preliminary Utility Guidelines Available - Very Limited Study on Safety Requirements 	<ul style="list-style-type: none"> - No Guidelines Concerning Need of an Isolation Transformer - Unresolved Issue Concerning Positive Means of Disconnection for Large Number of P.V. Sources 	<ul style="list-style-type: none"> - Establish Viable Safety Requirements - Revisions in the NEC and Other Applicable Codes - Hazardous Conditions Caused Due to Self Excitation of Line-Commutated Inverters
Metering	<ul style="list-style-type: none"> - Errors in Metering Real and Reactive Energy if Present Meters Used 	<ul style="list-style-type: none"> - Limited Knowledge of Impact of Harmonics on Induction-Disk Meters 	<ul style="list-style-type: none"> - Lack of Standardization Concerning Metering of Energy Under Non-Sinusoidal Conditions 	<ul style="list-style-type: none"> - None Recommended at This Time (EPRI and DOE Work in Progress)
Utility System Protection (Over-current & Others)	<ul style="list-style-type: none"> - Adverse Impact on Reliability of Electric Service - Risk of Damage to Customer and Utility Equipment 	<ul style="list-style-type: none"> - Initial Studies Made to Determine Impact of Distributed P.V. on System Overcurrent Protection 	<ul style="list-style-type: none"> - Lack of Distribution System Design Guidelines Concerning the Impacts on Protection Due to Fault Contributions of P.V. Systems, Particularly under Resonant Conditions 	<ul style="list-style-type: none"> - Survey of Present Distribution Protection Practices - Models for P.V. Systems During Faults - Software for Distribution System Fault Analysis - Simulations to Determine Impact on Utility Protection Practices

Table ES-1. Qualitative Summary of the Various Issues (Contd.)

Issue	Risk to Utility Customer, or PV System	State of Present Knowledge	Areas of Concern	Future Work Required
Distribution System Stability	<ul style="list-style-type: none"> - Nuisance Tripping at the Lateral, Feeder or Substation Level - Risk of Damage to Customer and Utility Equipment 	<ul style="list-style-type: none"> - Not Much is Known 	<ul style="list-style-type: none"> - Lack of Understanding of Dynamic - Interactions Between Various PV Systems, Other DSGs and the Utility System 	<ul style="list-style-type: none"> - Dynamic Models for PV Systems - Dynamic Models for other DSGs - Dynamic Analysis Techniques - Simulation to Determine any Undesirable Dynamic Interaction and Impact on PV Control Systems
System Unbalances	<ul style="list-style-type: none"> - Problems with Nuisance Tripping of Protective Devices - Equipment Overheating 	<ul style="list-style-type: none"> - Limits on Voltage Unbalance for Induction Motors Known - Mathematical Procedure to Calculate Unbalances (Symmetrical Components) Well Established 	<ul style="list-style-type: none"> - Uncertainty Whether Rating of Single Phase PV Systems and Maximum PV Penetration at Lateral, Feeder Level May Be Limited Due to Unbalance Considerations 	<ul style="list-style-type: none"> - Limits on Voltage Unbalance for Various Appliances and Equipment - Steady State Models for PV Systems - Simulations to Assess Impacts on PV System Size and Penetration
Distribution System Planning and Design	<ul style="list-style-type: none"> - Options and Lead Time For Utility Design to Accomodate PV Reduced 	<ul style="list-style-type: none"> - Initial Impact Assessment of DSGs on Utility Distribution System Planning and Design Made 	<ul style="list-style-type: none"> - PV Program Designs of PV Systems May Not Be Compatible With Future Distribution Systems 	<ul style="list-style-type: none"> - None Recommended at This Time (DOE Work in Progress)
Bulk System Stability	<ul style="list-style-type: none"> - Adverse Impact on Reliability of Service to Large Number of Customers 	<ul style="list-style-type: none"> - Techniques to Determine Bulk System Stability (without PV) Well Established 	<ul style="list-style-type: none"> - Could Impose Limits on System Wide Penetration of PV Sources 	<ul style="list-style-type: none"> - Modifications in Existing Techniques to Determine Impact of Large PV Penetration on Bulk System Stability
System Operations	<ul style="list-style-type: none"> - Excessive Swings in System Frequency - Higher Costs for Spinning Reserve and Standby Generation 	<ul style="list-style-type: none"> - Little Effort Made to Study This Issue 	<ul style="list-style-type: none"> - Lack of Understanding of a Large PV Penetration on Dispatching, Automatic Generation Control, Unit Commitment and Scheduling 	<ul style="list-style-type: none"> - No Recommendations at This Time

Table ES-2. Quantitative Assessment of the Present Status of Various Issues

Issue	Present Status	Impact
PCS Overvoltage Protection	8	Technology Readiness (TR)
Utility System Overvoltage Protection	4	
PCS Protection (Overcurrent & Others)	5	
Source Stability	3	
Voltage Regulation	3	
Harmonics	4	
Safety and Code Requirements	3	
Metering	3	
Utility System Protection (Overcurrent & Others)	3	Large Local Penetration (LLP)
Distribution System Stability	0	
System Unbalances	4	
Distribution System Planning	3	
System Operations	1	Large System Penetration (LSP)
Bulk System Stability	3	

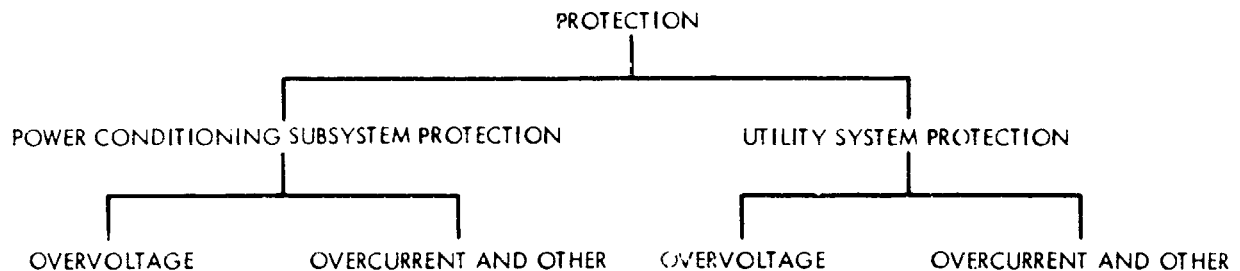


Figure ES-1. Breakdown of the Protection Issue

b. Utility System Overvoltage Protection. The utility system itself must be protected against overvoltages originating from resonant conditions caused by the presence of the PCS. An overvoltage of great magnitude could damage power system components.

c. PCS Protection (Overcurrent and Others). The PCS must be properly protected against overcurrent, undervoltage and over- or under-frequency due to faults in the utility, the PCS itself, or any other phenomena. This requires coordination with the utility system so that the PV sources can be disconnected properly. If the PV sources continue to feed what otherwise would have been temporary faults within the utility system, they may become permanent and cause prolonged interruption of service and substantial damage to the PCS.

d. Utility System Protection (Overcurrent and Others). Utility power distribution systems connected with distributed PV sources must have adequate protection against overcurrent and other disrupting phenomena to protect the integrity and reliability of service to all customers connected to that system. It is possible that large numbers of distributed PV sources could adversely affect time/current coordination of the protective devices and, thereby, the reliability of the electrical service.

Conclusions

Much is known about surge protection of devices and distribution systems. Based on this knowledge and existing guidelines and standards, proper protection for PV systems can be provided.

Resonant overvoltages are system- and application-specific. Some preliminary guidelines to avoid such overvoltages do exist, but they are suggestions rather than any strong recommendations.

Some initial studies indicate that distributed PV systems will have a minimal impact on the coordination of distribution system protective devices. More detailed analysis should be performed to substantiate this point of view.

Little work is being done in the important area of PCS protection. Conceptual designs of PCS for PV applications exist, but a detailed system analysis of the operating environment for a proper selection of the required protective devices is lacking. Such a system analysis should lead to satisfactory coordination of PCS and utility protection.

Some guidelines on protection requirements for dispersed generators have been formulated by various utilities. These guidelines deal only with general requirements and may not be entirely applicable to a multiplicity of sources.

2. Stability

Conventionally, stability is considered to be a system's ability to maintain synchronous operation after a disturbance. Control theory defines

it as the system's ability to find a new, desired equilibrium state following a disturbance. Both definitions are applicable. Due to its complexity, stability is divided into three parts for discussion (Figure ES-2).

a. Source Stability. The individual PV system, connected to a utility, must maintain stable operation. Stability of the feedback control system is a concern. Fluctuations that may result from improper controls could damage the PV system or cause nuisance tripping of PV-system protective devices.

b. Distribution System Stability. Distributed PV systems and other DSGs that are connected to a single substation must be able to maintain synchronous operation in the face of system disturbances. Undesirable interaction between various PV sources and DSGs connected to the same distribution system could cause nuisance tripping at the lateral, feeder or substation level. This would cause unnecessary outages to customers. It could also result in damage to customer equipment connected to the system.

c. Bulk System Stability. A large system penetration of PV systems could cause problems with bulk system stability during excessive fluctuations in PV output (due to passing cloud cover, etc.). Any such concern could limit the maximum PV penetration on any given utility system.

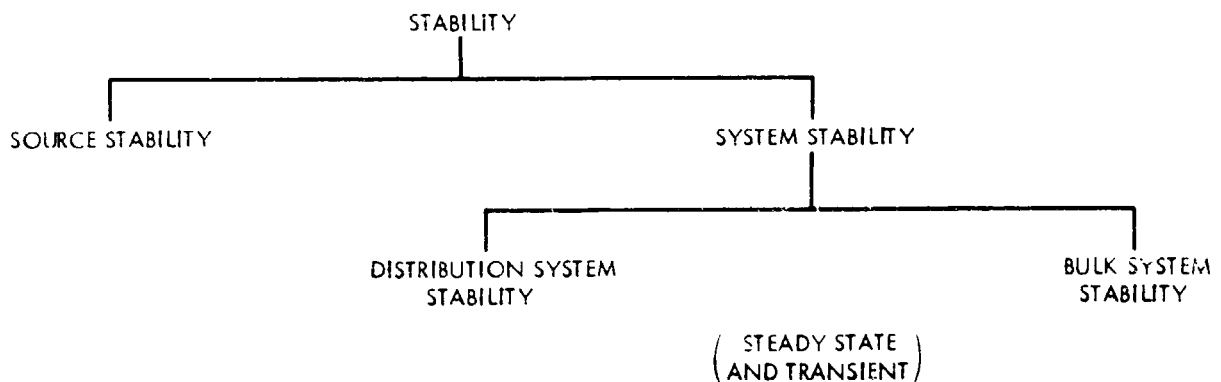


Figure ES-2. Breakdown of the Stability Issue

Conclusions

Initial studies with individual PV systems indicate that problems of source stability might develop. Not much is known about the dynamic interaction of PV systems with each other and with other DSGs connected to the utility system.

Techniques to study bulk system stability (without PV) are well established. The impact of large PV penetration on bulk system stability may be studied through the modification of existing techniques.

3. System Unbalances

Single-phase PV systems may, at times, accentuate unbalances in system voltage and current. These unbalances may cause operational problems such as overheating and protective-device nuisance tripping. Single-phase PV systems may have size and penetration limits imposed on them because of the potential to increase system unbalances beyond tolerable limits.

Conclusions

The effects of voltage unbalances on induction motors are well documented; the allowable voltage unbalance is approximately 2%. Little is known about the effects of system unbalance on other three-phase appliances and equipment. The mathematical procedure to calculate unbalances (symmetrical components) is well established. The inputs needed such as phase and line voltages and currents, impedances, etc., may be hard to obtain.

4. Voltage Regulation and Reactive Compensation

Utility systems are expected to maintain proper voltage for their customers within a narrow, acceptable band. PV systems connected to the utility may interfere with voltage regulation by substantially changing the normal flow of reactive power. If proper voltage cannot be maintained when PV is added, changes in the distribution system or the PCS may have to be made. The cost of these changes may be passed on to PV owners.

Conclusions

The problems of voltage regulation and reactive compensation are inseparable; one affects the other. Surprisingly, there seems to be no standard definition of power factor (or reactive power) under non-sinusoidal conditions.

It may appear to be economical to correct lagging power factors by adding capacitors at the terminals of the PV installation. Such capacitors, however, may lead to resonant conditions which can be hard to eliminate.

Voltage regulator operations may be affected by reverse power flow and changing power factors. Little analysis has been performed on this issue.

No utility guidelines could be identified that specify an acceptable voltage band or limits on the reactive power for the operation of a DSG connected to the utility. Some power conditions, however, offer the ability to control reactive power and could, therefore, prove to be beneficial for voltage control.

5. Harmonics

Utility systems ideally operate at a fundamental frequency of 60 Hz for voltage and current. Any harmonics present in the system can adversely affect the system operation and its loads. PV systems will produce harmonics in both current and voltage because of the dc/ac conversion process. If the PV system produces excessive amounts of harmonics and causes problems for the utility power system, the utility may ask the PV owner to shut down and correct the problem.

Conclusions

Only a few utilities in the United States have guidelines or specifications on harmonics. Most would require shutdown of the harmonic-producing DSG if it interferes with their service. Many European guidelines for harmonics exist, but their applicability to high PV penetration is not clear. A summary of the various guidelines and specifications indicates that a 5% system voltage distortion factor (VDF) with a 3% limit on any single voltage may be acceptable, but large variations in the various guidelines makes the use of this number very limited.

There is only limited information available regarding the maximum tolerable limits of harmonics for appliances and power system equipment. Little effort has been devoted to the measurement of background harmonic levels on existing utility systems. Both EES and EPRI have initiated programs in this area.

Other factors affecting allowable harmonics limits are Telephone Interference (TI) and Electromagnetic Interference (EMI). Much is known of the factors that determine Telephone Interference. Investigation of EMI is needed to determine its conformity to FCC regulations.

Some software is available to study the propagation of harmonics on power systems. It may be possible to use it for some initial studies with dispersed PV systems.

6. Safety and Code Requirements

Proper guidelines must be developed for the safe installation and operation of PV systems so that the owners of such a system and the utility operating personnel will be protected. Unless the safety requirements are established within the framework of product safety standards, building and electrical codes, and utility codes, approval from the code enforcement officials and the utility could be withheld.

Conclusions

Approved guidelines for grounding of PV arrays and PCS do not exist. Modifications to the National Electrical Code (NEC) are required to address the specifics of PV installation.

There is no general agreement on the need or the exact benefit of an isolation transformer.

Visible manual disconnects are a personnel safety requirement that appears to be universal. However, manual disconnects may be impractical when there is a large penetration of PV sources. The EES program is addressing these issues.

Based on concern for utility personnel safety, the ability of line-commutated inverters to feed a utility system during a utility outage must be investigated.

7. Metering Requirements

Meters must be modified if they are to accurately measure the exchange of energy between the PV system and the utility for billing purposes. Meters now in use can accurately measure the fundamental component of power (or energy) but are inaccurate under non-sinusoidal conditions.

Conclusions

PV system metering requirements will be determined by utility rate structures and a cost/benefit analysis of the various alternatives by the PV system owner.

Utilities have shown little concern for how the harmonic content of the output of the PV system will be measured. Apparently, meters that accurately measure real and reactive energy under non-sinusoidal conditions are not available.

8. Operations

The maintenance of continuity and quality of service is the most important objective in the operation of an electric utility. Generation adjustments that match load requirements must be made in real time. A common practice is to distribute power generation among the various generating units so that power production will be economical. Figure ES-3 categorizes power system operations into three basic functions.

a. Automatic Generation Control. Automatic Generation Control consists of Load Frequency Control and Economic Dispatch. Load Frequency Control is the regulation of electric generator output within a prescribed area to maintain scheduled system frequency and established interchange of power. When there is large PV penetration in a power system, the normal fluctuations in PV output could cause excessive swings in system frequency unless proper control is initiated. Economic Dispatch Control is the

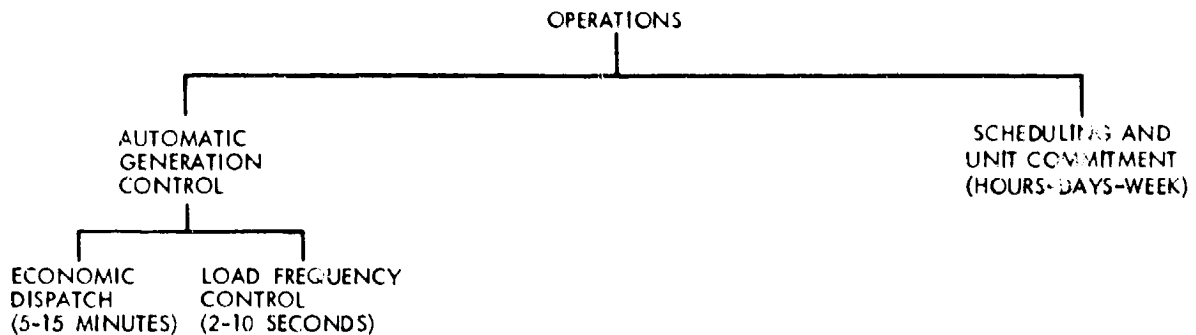


Figure ES-3. Breakdown of the System Operations Issue

allocation of generation requirements among alternative sources for optimum economy. The basic methods for economic dispatch are not expected to change as PV is integrated into the utility.

b. Scheduling and Unit Commitment. Scheduling is an advance commitment (within a few hours) of the various generating units to meet the expected load, based on economic considerations. Unit Commitment covers a longer period of time (up to two weeks) and is based on availability of generating units. Since PV generation cannot be accurately predicted, allowances may have to be made in terms of increased spinning reserve and standby generation.

Conclusions

It appears that PV systems introduced into the utility will not affect total systems operations until their penetration is large. Then, the impact will probably be both economic and technical because of the displacement of energy and the possible rapid power fluctuations caused by solar transients.

9. Distribution System Planning and Design

Because of the impacts of PV on protection, voltage regulation and other issues discussed previously, modifications in the design and planning of distribution systems appear to be necessary. Further, if PV is not considered in the planning phase, its entrance into the utility system will occur in the design phase. Thus, the lead time for change would be shortened and the available options lessened. If PV is not considered in design efforts in advance of need (such efforts may be triggered by an entrepreneur installing PV), the early and highly visible projects may accidentally indicate that PV is more trouble than it is worth.

Conclusions

The DOE Electric Energy Systems Division (EES) has sponsored studies to identify the ways DSGs can be incorporated into the planning and design of future distribution systems. The results of these studies will be of great value in resolving this technical issue.

C. RECOMMENDATIONS

Recommendations for future work to resolve most of the issues are summarized in Table ES-1. In most cases, the work involves field measurements, laboratory testing, model and software development and extensive simulation. Due to the possibility of having many designs of PCSs available for PV application, the required models should be developed for the various generic types of PCSs, such as line-commutated, self-commutated, high-frequency links, etc. To the maximum extent possible, the results obtained through simulation and analysis should be verified in the field.

SECTION I

INTRODUCTION

A. BACKGROUND

Photovoltaic (PV) power generation has a great potential for providing a substantial portion of this country's future energy needs. It provides an inexhaustible and relatively clean energy source. The technical feasibility of PV power generation has been a demonstrated fact for many years, but costs of systems currently being produced have confined their use to small-scale, remote applications. It has been determined that to achieve significant fuel displacement, the PV systems must be connected to the utility power system. According to the Photovoltaic Multi-Year Program Plan,¹ "distributed grid-connected electrical and total-energy residential systems should be able to displace significant amounts of centrally generated electricity, first in the southwest and subsequently throughout most of the United States. Intermediate-sized commercial, institutional, and industrial on-site systems should provide a similar option. Utilities should ultimately be able to augment their generating capacity with larger-scale systems."

However, for the utilities to consider augmenting their conventional generating capacity with substantial PV generation and the customers to accept it, many utility interface technical issues must be resolved. These issues arise from the following major differences between PV and conventional generation:

- (1) PV generation is stochastic in nature while conventional generation is deterministic (barring forced outages of conventional generating units).
- (2) Solar cells generate dc power; conventional units generate ac power.
- (3) In distributed PV applications, the PV sources will be connected to the distribution system. Thus, the functional requirements of the distribution system will change with a consequent impact on its design and operation.

So far, limited engineering effort has been expended to identify and resolve the critical issues related to the satisfactory integration of PV generation sources into the utility power system. This may be due partly to the fact that, at present, the total PV kilowatt capacity connected to the grid is quite limited, and none of these operating systems are considered satisfactory from the standpoint of the utility. There is a real possibility that, in the future, PV systems will have to be integrated into utility systems with other types of DSGs such as fuel cells, batteries, and wind generators. This makes

¹National Photovoltaics Program Multi-Year Program Plan, Photovoltaic Energy Systems Division, September 1980.

the problems of PV integration even more complex. The guiding principle to be followed is that the integration should not result in any adverse impact to the utility, PV owner, or other customer.

The interaction of distributed PV systems in a future utility is shown in Figure 1-1. The Power Conditioning Subsystem consists of the dc/ac inverter and its controls, filters, protective equipment and associated switching. The other DSG (Distributed Storage and Generation) devices connected to the distribution system may be fuel cells, batteries, wind generators, and other PV systems.

Some of the key questions that can arise from such an interaction are:

- (1) What quality of the power (waveform distortion, power factor, etc.) produced by PV systems is acceptable to the utility?
- (2) What are the Power Conditioning Subsystem requirements so that this quality can be achieved economically, safely, and reliably?
- (3) How should the Power Conditioning Subsystem be controlled so that it operates in a stable mode and ensures optimal power transfer between the PV array and the utility power system?

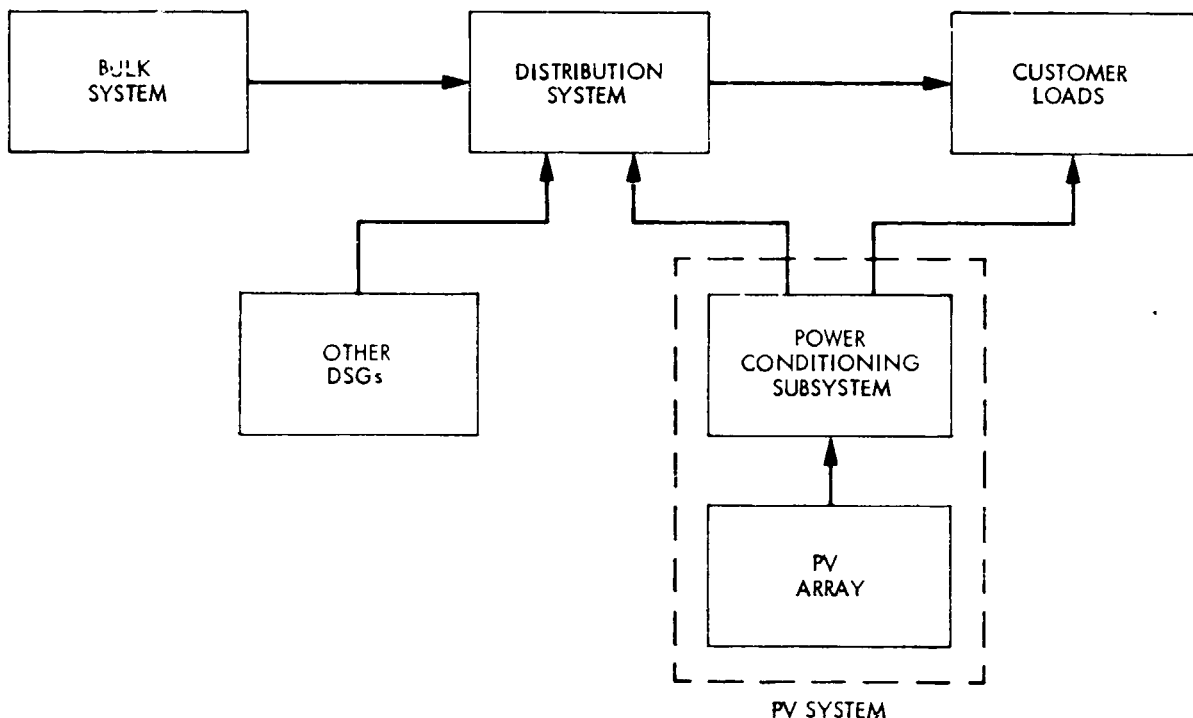


Figure 1-1. Interactions of the Various Systems in a Future Utility

- (4) How should the transmission or the distribution system be modified to make the parallel operation of the PV generation sources possible? Can any of the power quality requirements be achieved by modifying the transmission or distribution system, rather than by placing uneconomical constraints on the Power Conditioning Subsystem?
- (5) How do other DSGs connected to the distribution system impact the design of the Power Conditioning Subsystem?

For successful integration of distributed PV systems into the present day utility power system, these questions must be answered soon.

B. TASK OBJECTIVES

There are major issues related to the integration of PV generation into the utility systems that need resolution. These issues will have important bearing on PV systems development and the utility transmission and distribution system design. As such, they can seriously impact the U.S. Department of Energy's (DOE) long-range cost and performance goals and, thus, the acceptance and inclusion of PV generation by the utilities and customers.

The objectives of this study were:

- (1) Define the various problems related to the integration of distributed PV generation into the utility systems and describe their impacts.
- (2) Study all the available literature on the subject including:
 - (a) Work managed and performed by the various national labs such as Sandia and MIT Lincoln Lab.
 - (b) Work sponsored by the DOE Office of Electric Energy Systems (EES) and other DOE offices on integrating new energy sources.
 - (c) IEEE guidelines and/or standards.
 - (d) EPRI-sponsored research.
 - (e) European utility guidelines and/or standards.
 - (f) Research reported in IEEE/IEE journals, etc.
- (3) Apply the findings of the literature search to the problems defined above under (1) and determine if a satisfactory solution for any of the problems exists.
- (4) Establish expectations for currently suggested studies and research.

- (5) Identify further work required in this area including an approach to solving the various problems.

This task has emphasized technical issues concerning residential and intermediate size systems with no dedicated electrical storage. Although central station plants are not specifically addressed, some of the issues raised here do apply to them also. However, analysis of such issues was beyond the scope of the current study.

C. TASK ACCOMPLISHMENTS

The various major issues which were identified during this task are as follows:

- (1) Protection.
- (2) Stability.
- (3) System unbalances.
- (4) Voltage regulation and reactive power requirements.
- (5) Harmonics.
- (6) Utility operations.
- (7) Safety.
- (8) Metering.
- (9) Distribution system planning and design.

As will be explained later, some of these issues had to be subdivided still further to better define their impacts.

In this report, each major issue is discussed in an individual section. Each issue is assigned a proper definition and the risks posed to the PV program are described. Also, their scope and impact are briefly discussed. A brief review of all the relevant references revealed by an exhaustive literature search is presented for each section. A compilation of these references appears in Appendix A. Any guidelines or standards available on the various issues are also discussed. Other references which are only marginally useful for the present study are listed in Appendix B. Based on the literature search, the current and future status of the various issues are clearly indicated. The projections of future status are based on the premise that the currently planned or proposed DOE studies take place as scheduled. Finally, a plan of action for timely resolution for most of the issues is recommended.

A survey was also conducted of two local utilities (Southern California Edison and City of Pasadena Department of Water and Power) to determine their current design and operating practices for distribution systems. This

information was helpful in ensuring that the various technical issues identified related to existing utility distribution practices. The results of the survey are presented in Appendix C.

This study also found that many organizations are studying various aspects of interface requirements for dispersed generators. A list of such organizations is given in Appendix D. It is recognized that this list is not complete. The authors would appreciate knowledge of other organizations involved in such studies.

D. CONCLUSIONS

Much information has been uncovered on the various issues identified in this study which may arise from the integration of distributed PV systems into utility power systems. Although many isolated efforts to resolve the various issues have been identified, most of the issues remain unresolved. An early resolution of these issues is imperative to meet the goals set forth in the DOE Photovoltaic Multi-Year Program Plan. The DOE has recognized the need to speedily resolve issues arising from integrating the various new energy technologies into the utility power system. It has initiated, or is in the process of initiating, a set of activities to resolve the issues. The Division of Electric Energy Systems (EES) has the primary responsibility to coordinate all integration activities within DOE. As such, the EES program activities were studied and integrated into the findings of this study.

The literature review yielded facts about each issues status that could be summarized (Table 1-1). The scale is from "0" to "10", with resolved issues being "10" and issues with little information available being "0". The uncertainty of the DOE budget precludes any effort to state the future status of these issues. However, analysis of these DOE future activities, proposed before the budget revisions, appears in the body of this report. The table also indicates the impact of each issue on various levels of penetration. These levels are defined below:

1. Technology Readiness (TR)

For the purposes of this study, Technology Readiness (TR) is defined as the installation of one PV array connected to a utility system.

2. Large Local Penetration (LLP)

This is defined as a level of penetration of PV sources on a distribution system feeder when the total PV output is around 10% of the feeder load.

3. Large System Penetration (LSP)

This is defined as a level of penetration of PV sources on any utility system when the total PV output is around 10% of the system load.

Table 1-1. Summary of the Present Status of the Various Issues

Issue	Present Status	Impact
PCS Overvoltage Protection	8	
System Overvoltage Protection	4	
PCS Overcurrent and Other Protection	5	
Source Stability	3	Technology Readiness (TR)
Voltage Regulation	3	
Harmonics	4	
Safety and Code Requirements	3	
Metering	3	
Utility System Overcurrent and Other Protection	3	
Distribution System Stability	0	Large Local Penetration (LLP)
System Unbalances	4	
Distribution System Planning	3	
Bulk System Stability	3	Large System Penetration (LSP)
System Operations	1	

Although every effort was made to uncover all the relevant literature, it is quite possible that some useful material was overlooked. If so, any pertinent information may be forwarded to the authors for inclusion in future work.

E. RECOMMENDATIONS

Detailed recommendations are provided for a timely resolution of most unresolved issues. In most cases, they involve field measurements, laboratory testing, model and software development and extensive simulation. Due to the possibility of having many different designs of PCSs available for PV applications, the models should be developed for the various generic types of PCSs, such as line-commutated, self-commutated, high-frequency links etc.

Although it is not specifically described in the recommendations, the results obtained through simulation and analysis should be verified in the field if possible. The detailed planning for the full set of activities, including field verification is beyond the scope of this study.

SECTION II

PROTECTION

A. INTRODUCTION

This section describes protection of the utility system and the Power Conditioning Subsystem against various abnormal system operating conditions such as overvoltage, overcurrent, over/under frequency, etc. These abnormal conditions could originate either in the utility system or the PV system itself.

The issue of protection can be further divided into the categories shown in Figure 2-1. Each category is discussed below.

B. POWER CONDITIONING SUBSYSTEM OVERVOLTAGE PROTECTION

1. Definition

Overvoltage protection within the Power Conditioning Subsystem involves protection against transient overvoltages originating in the utility system or the PV system itself.

2. Risk

If these voltage surges are allowed to pass through directly without suppression, they could damage the components of the Power Conditioning Subsystem. The electronic components would be the most susceptible to damage due to their lower surge-withstand levels.

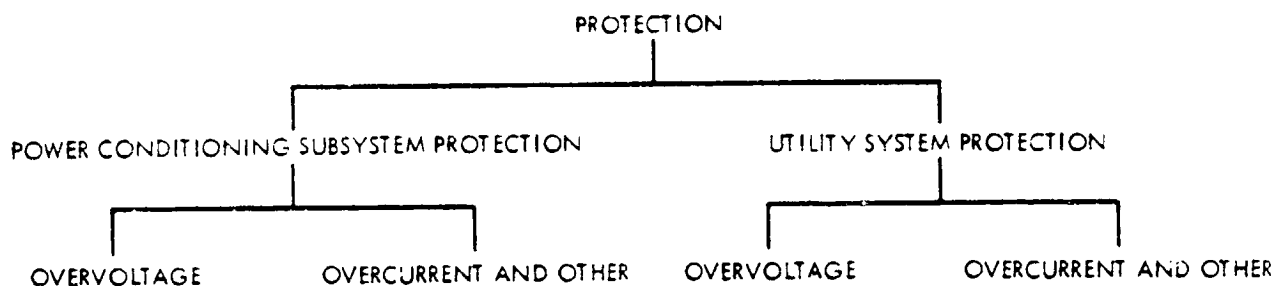


Figure 2-1. Protection Categories

3. Discussion

Because the Power Conditioning Subsystem is directly connected to the utility system, it is exposed to the transient overvoltages (or surges) occurring from time to time on the utility system. The transient overvoltages could be either of atmospheric or systemic origin. A prime example of the former is a lightning strike which can cause overvoltages of very short duration (order of microseconds). The magnitude of the overvoltage is dependent upon the lightning strike, the point of impact, and the system characteristics. Some examples of transients originating within the system are switching surges, ferroresonance, restrikes in switches and circuit-breakers, etc.

The magnitude of these transient overvoltages, even though a system dependent parameter, can vary from a few (~ 2) per unit² for switching surges to many times (~ 10) per unit for lightning surges. Electronic components used in power conditioning systems such as transistors, SCRs, diodes, etc., will be more susceptible to damage by these voltage surges than conventional power system components such as transformers, cables, switchgear, etc. It is not unusual to specify surge-withstand voltage levels as high as 10 to 20 times the normal voltage rating for these conventional components. However, to achieve the same withstand level for electronic components is not practical. It is imperative, therefore, to provide proper surge protection so that the exposure voltage is limited to a safe value.

C. UTILITY SYSTEM OVERVOLTAGE PROTECTION

1. Definition

Overvoltage protection within the utility system includes protection of the system against overvoltages originating due to the PV sources connected to it. There are overvoltages that originate within the utility system itself, but the current utility systems are adequately protected against them.

2. Risk

These overvoltages could be of great enough magnitude to seriously damage power system components such as capacitors, etc.

3. Discussion

The cause and the nature of these overvoltages arising from the interaction of the PV sources with the utility system is discussed here. Of the various types of conversion alternatives available, two approaches are commonly applied today.

²A magnitude of "X" per-unit is "X" times the rated system line-to-line voltage.

Current Fed Line-commutated (CFLC) inverters switch a dc current (using utility voltage for commutation) so that resulting output is an alternating waveform. The voltage at the output terminals is then a function of the driving point impedance looking into the terminals of the utility at the converter (which itself is a function of many variables). In other words, such a converter behaves as a current source.

Voltage Fed Force-commutated (VFFC) inverters switch a dc voltage (using their internal 'clocks' for switching purposes) so that the output represents an ac voltage waveform. The current waveform is then a function of the driving point impedance looking into the terminals of the utility at the converter. Such a converter behaves as a voltage source.

For the purpose of the analysis here, only ideal sources will be assumed. However, the ramifications of any impedances associated with these sources will also be discussed.

Figure 2-2 shows an ideal voltage source (self-commutated inverter) connected to a power system represented by a lumped inductance L and shunt capacitance C . The voltage source V_s is expected to be made up of many harmonic frequencies.

Under steady-state conditions, the voltage across the capacitance is given by:

$$|V_C| = |V_S| \frac{x_C}{x_C - x_L}$$

where

$|V_S|$ = magnitude of source voltage

$|V_C|$ = magnitude of voltage across capacitance

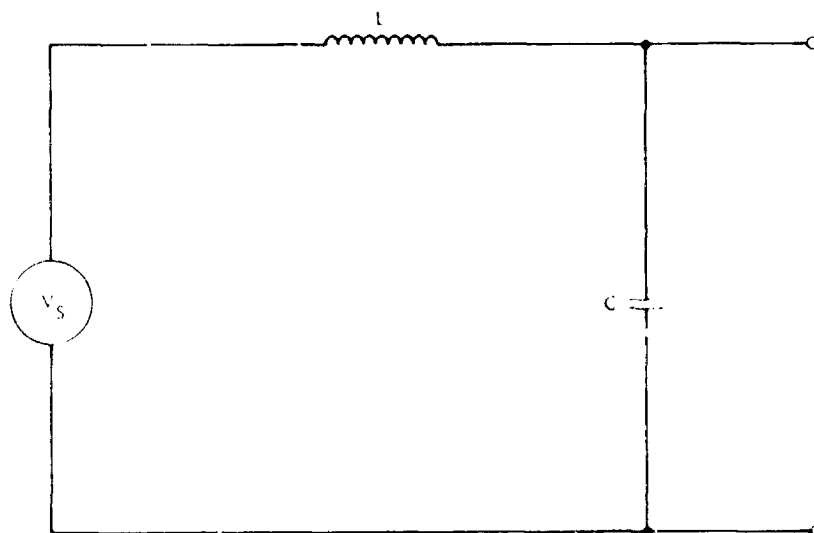


Figure 2-2. An Approximate Lumped Representation of a Power System

X_L = inductive reactance

X_C = capacitive reactance

for any frequency of interest.

At resonant frequency, $X_C \approx X_L$, and thus the voltage across the capacitance can theoretically go to infinity. However, because of damping associated with the source and system resistances, the voltage will be finite but possibly large in magnitude. Thus, to predict this magnitude, it is important to know the value of this resistance quite accurately.

Resonances can also occur if a current source inverter is employed. In such a case, resonances between parallel elements of the system will be of concern rather than the series resonances illustrated above.

Obviously, this is a very simplified analysis of an approximate representation of the power system. Its sole purpose is to give an insight to the problems of overvoltage which could occur from the interaction of the PV sources with the utility power system.

D. POWER CONDITIONING SUBSYSTEM PROTECTION (OVERCURRENT AND OTHERS)

1. Definition

Power Conditioning Subsystem (PCS) protection involves protection against any abnormal operating conditions such as overcurrent, undervoltage, or over/under frequency either from a fault on the utility system, an internal fault in the PCS, or any other phenomena. This would also include the proper coordination and/or disconnection of the PV source from the rest of the system under these abnormal conditions.

2. Risk

Continued feeding of the faults on the utility system by the PV source could cause what otherwise would have been temporary faults to become permanent resulting in prolonged interruption of service to a large part of the system. Improper coordination of the Power Conditioning Subsystem protection with the rest of the utility system could result in substantial damage to the Power Conditioning Subsystem.

3. Discussion

In overhead distribution systems, initially a large percentage of the system faults are temporary (such as a tree limb falling on a line, arcing insulators, etc). According to available statistics, 50 to 80% of the faults (both bolted and resistive faults) that occur on a system are temporary. Temporary faults are cleared by opening a recloser or a reclosing circuit-breaker to de-energize the circuit for a long enough time to let the fault clear by itself (such as an arc to extinguish). The recloser then automatically switches on and if the fault still persists, it switches off again. This opening and

closing sequence is repeated two to three times, depending upon the application. If the fault is still not cleared, the recloser is locked out in an open position and permanently disconnects the circuit until the fault is manually located and removed. A typical recloser operating sequence is depicted in Figure 2-3.

If these temporary faults are allowed to persist, even at the low levels of fault current available from PV systems, they might very well result in permanent faults. This would cause a complete circuit to be disconnected until the fault was removed manually. There is a distinct possibility that PV sources connected to the system may play a role in causing temporary faults to become permanent. This can be illustrated with reference to Figure 2-4 which shows a portion of a typical utility distribution system. Because the PV systems are connected to the utility line, they will keep on feeding the fault unless disconnected individually from the utility line. This could be accomplished by providing fault-sensing logic which would sense any abnormal change in operating parameters (such as frequency, current or voltage) and disconnect the PV system. However, there could be situations (such as a high resistance fault and low insulation condition) in which these parameters might stay within the tolerable range even under faulted conditions. The PV systems would continue feeding the fault until the fault became permanent. However, this is a hypothetical situation and will have to be verified by actual analysis.

It is also important that the opening of the PV system circuit-breaker be properly time-coordinated with the utility protective system. The circuit opening should be at least as fast as the operation of the utility side recloser. A switching logic incorporating sequential opening and closing (to coordinate with utility recloser) may also have to be used for higher reliability. This would ensure that the PV system is not disconnected permanently on temporary utility faults.

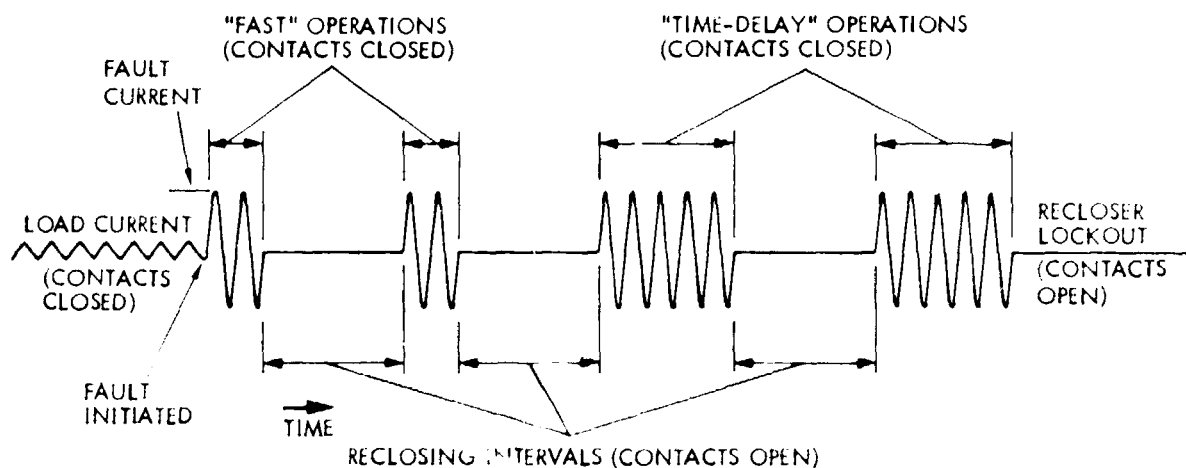


Figure 2-3. A Typical Recloser Operating Sequence

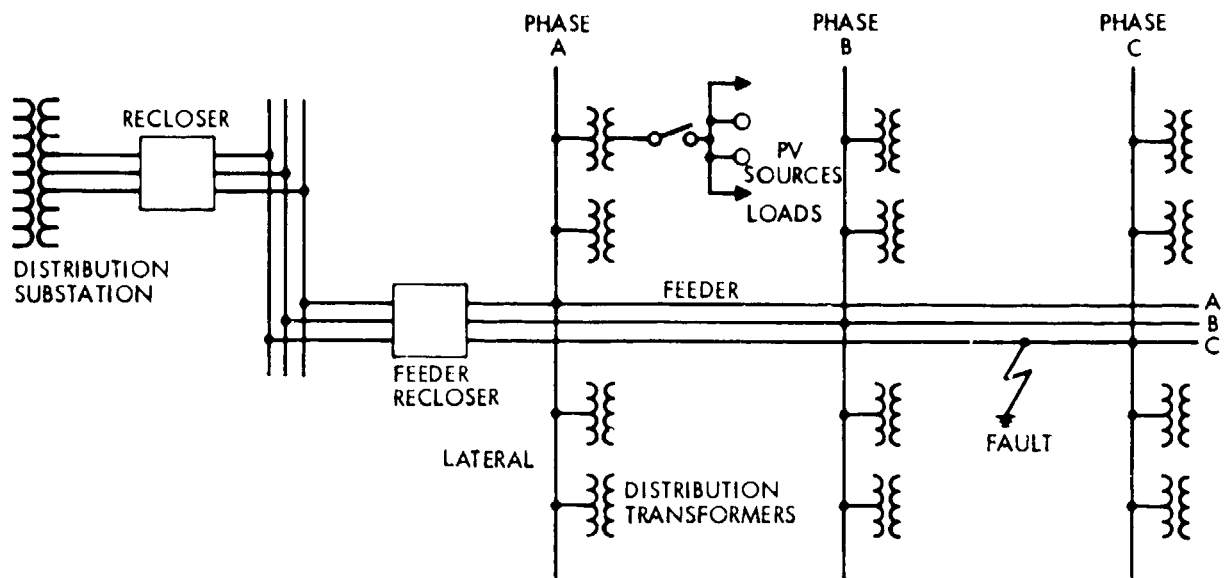


Figure 2-4. A Typical Distribution System with PV Sources Connected

For single line-to-ground faults, another problem may develop which can again be explained with reference to Figure 2-4. For a fault on phase C, hopefully all the PV sources on that phase will be disconnected from the system. However, the sources on the sound phases will continue operating and feeding energy to local loads even after the feeder recloser at the substation transformer trips off. If the margin between available PV generation and system load is large, a significant change in system frequency and voltage may result. This would cause the individual fault-sensing logic to sense this abnormal condition and switch off the PV sources. If such is not the case and PV sources continue feeding the system, there is a distinct possibility that the utility source, when closed again, will close out of synchronism with the PV source, causing considerable damage. Any three phase loads still served by remaining two phases of the PV systems may also be subjected to "single-phasing," a potentially harmful condition.

E. UTILITY SYSTEM PROTECTION (OVERCURRENT AND OTHERS)

1. Definition

Protection of the utility distribution system (with distributed PV sources connected) includes proper protection under various faulted conditions so that the reliability of service remains unaffected.

2. Risk

A large number of distributed PV sources connected to the utility distribution system may adversely impact the time/current coordination of the various protective devices. This would increase the probability of outages to the customers connected to the system.

3. Discussion

The overcurrent protection system is installed to perform numerous functions in a distribution system. Some of the functions include isolating permanent faults, minimizing fault location and clearing times, preventing equipment damage and minimizing the probability of disruptive failure and safety hazards to public and system operating personnel. A typical overcurrent protection system for a radial distribution system is given in Figure 2-5. This system shows a three-phase main feeder protected with a three-pole circuit-breaker or recloser at the distribution substation. The single-phase lateral circuits are connected to the three-phase main through either fuses or sectionalizers. Any switching arrangements for sectionalizing or emergency ties to adjacent feeders are not shown here but do exist in practice.

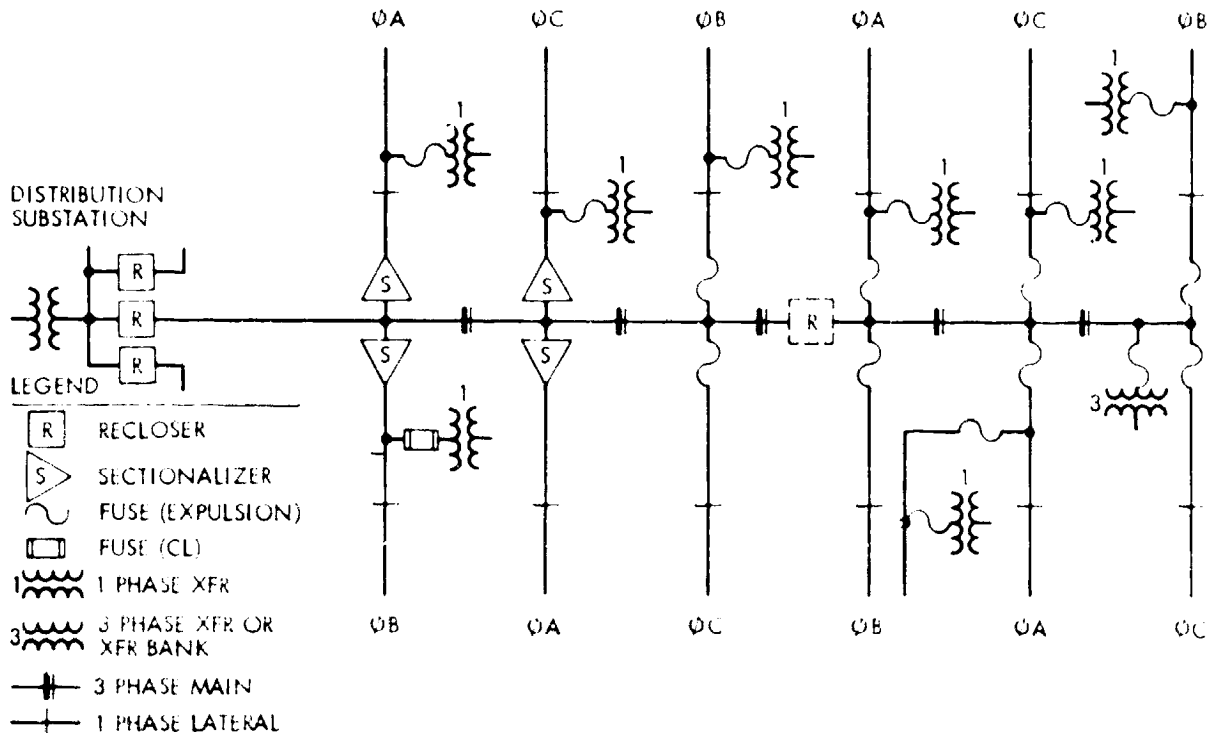


Figure 2-5. Simplified Single-Line Diagram of a Distribution Feeder to Illustrate Locations of Overcurrent Protective Devices (from Reference 6)

To maintain a high reliability of electrical service, it is necessary that only faulted portions of the system be disconnected and isolated from the rest of the system. This is achieved by properly selecting protective devices (reclosers, fuses and sectionalizers) and coordinating them by their time-current characteristics. To properly use these characteristics, the lowest and highest expected values of the fault current observed by the protective devices must be known. In present day distribution systems, these values are determined by simple, short-circuit calculations because the only source of fault current is the utility system (ignoring small contributions to fault current by motors on the system). Even if the contribution of motors is included, simplified procedures have been developed to include their effect. Once the distributed PV sources are connected to the system, they will start contributing to the fault current, even though their overall current contribution will be much smaller than the utility system. Besides being a function of insolation (and thus the time of day), this portion of the fault current will be a function of the number of PV sources on the feeder and their location. The fault current contribution of the PV sources may not be great, however it might be enough to adversely impact the time-current coordination of the protective devices on the system. Local tuned circuits might cause severe overcurrents which can also have adverse impacts on the coordination. To accurately determine fault currents with PV sources present, extensive fault studies must be carried out which would be much more complex than identical studies for present day systems.

F. REFERENCES

1. Photovoltaic Utility/Customer Interface Study, Final Report, Westinghouse Electric Corp. for Sandia Labs under Contract #13-2228, December 1980.

Chapter 2 discusses the protective relaying requirements for interconnection of residential, industrial, and commercial PV systems to the utility. For the residential systems, most of the protection requirements are assumed to be with the Power Conditioning Unit (PCU) and are not discussed in detail. For the commercial and the industrial case, detailed single-line diagrams showing the various types of protective devices are given. Again the PCU protection requirements are not discussed in detail. The emphasis is on the protection of utility interconnection.

It would have been more helpful if the report had highlighted the actual protection requirements for the PCUs rather than for just the utility interconnections. The practices for these are reasonably well established.

2. Kimbark, E. W., Direct Current Transmission, Vol. I, Wiley Interscience, 1971.

Chapter 7 discusses the protection requirements of HVDC systems and, in particular, for converter stations. Four categories of protection are discussed:

- (1) Overvoltage protection, accomplished similarly to that of an ac system.
- (2) Overcurrent protection, accomplished by valve control.
- (3) Damping of voltage oscillations by using valve dampers.
- (4) Avoiding commutation failures and limiting short-circuit currents by using dc reactors.

The analysis developed is valid for only large size HVDC converters. Some of the recommendations provided could very well apply to small converters in utility interactive applications.

3. Study of Dispersed Small Wind Systems Interconnected with a Utility Distribution System, Interim Report by Systems Control Inc. for Department of Energy, Contract #DE-AC04-76DP03533, March 1980.

The purpose of this study was to determine the feasibility of and to develop strategies for safely connecting dispersed small wind systems to the distribution system of an electric utility.

Analysis of an induction generator's response during a three-phase utility line fault indicates that the impedance of a small induction generator is greater than the utility's short-circuit impedance. Consequently, the current contribution of the small induction generator is not enough to cause erroneous operation of the utility's overcurrent devices. This relative difference in impedance allows the small induction generator to respond to a three-phase utility fault at the utility's substation as if the fault occurred at the generator's terminals. This result did not vary with changes to the number of small wind systems connected to the feeder, and the impedance of the utility fault.

These results suggest that individual small wind systems are unlikely to contribute sufficient fault current to cause coordination problems. This is because of the relatively large impedance calculated for the small wind system compared with the utility's short-circuit impedance.

A comparison of the small wind systems of the synchronous generator and induction generator with the self- and line-commutated inverter systems shows that the synchronous and induction generators pose a greater potential problem to the coordination of the utility's protection equipment. Specifically, synchronous generators are voltage sources which can continuously feed a utility fault until they are disconnected by an interrupting device. Induction gen-

erators contribute to fault current within the first few cycles. In contrast, the contribution of self- and line-commutated inverters to three-phase utility faults is usually interrupted within the first cycle by the failure to commutate.

For utility faults with impedance the induction generator's voltage decay time constant was found primarily dependent on the generator's machine constants. These wind-turbine generators are unlikely to contribute fault current after two cycles.

These conclusions, particularly that the contributions of self- and line-commutated inverters to three-phase utility faults is usually interrupted within the first cycle, are interesting. This would imply that there would be no problem of protective device coordination with distributed PV systems connected.

4. Assessment of Distributed Photovoltaic Electric Power Systems, Final Report by JBF Scientific for EPRI Project RP 1192-1, July 1980.

The purpose of this study was to analyze the technical and economic potential of distributed photovoltaic electric-power systems in the United States by 1995 and to assess the probable impact of PV systems on the U.S. electric utility network.

A methodology was developed to assess potential impacts on Transmission and Distribution (T&D) systems associated with the installation and operation of distributed PV units. The methodology applied static (single point in time) analytical techniques on a synthetic T&D network model. The model, developed from earlier work on T&D models funded by EPRI, included one 69 kV subtransmission circuit and four 12 kV distribution circuits. The distribution circuits consisted of overhead and some underground lines in urban, suburban and rural locations.

Photovoltaic systems were introduced in the subtransmission and distribution circuits as lumped generation. The photovoltaic systems were applied at several penetrations with multiple output characteristics.

The following summarizes the potential impacts on the protection requirements of the utility distribution system when distributed PV is installed. A typical V-I characteristic of a PV array showed that the fault current would be only 18% more than the rated current. Therefore, PV would be a very weak source of fault current. Typical primary and secondary short-circuit duties are around 10,000 amps, while PV fault currents appeared to be less than 100 amps. In addition, distribution system sectionalizing equipment is generally not directional. Thus, PV backflows will not contribute significantly to utility system primary and secondary fault currents or to sectionalizing equipment ratings.

Potential distribution system sectionalizing problems appear to consist mainly of coordinating PV relaying schemes with utility relaying. Two possible problem areas are the coordination of reclosers with PV relaying and potential PV impact on inrush currents during cold load restoration.

Overcurrent and undervoltage relays will probably be required to coordinate dispersed PV relaying and control with utility sectionalizing equipment. Current unbalance relaying may be required on three-phase PV. In addition, there will probably be synchronizing and timing requirements for reconnecting PV systems after a fault.

This study provides an interesting first-hand look at the protection problems of distributed PV systems. However, the results only provide an initial assessment of the various problem areas and more detailed analyses must be performed before any firm conclusions can be drawn.

5. Study of Distribution System Surge and Harmonic Characteristics, Final Report EL-1627, Prepared by McGraw-Edison Company for EPRI, November 1980.

Section 4 of this report discusses the transient voltage surges on distribution systems. The purposes of this section were to:

- (1) Define the characteristics of voltage surges that exist on distribution systems at the connection points for power conversion equipment.
- (2) Define the effects of voltage surges on power conversion equipment.

The causes of various types of voltage transients on distribution systems such as lightning, capacitor and circuit switching operations, and current-limiting fuse operation were investigated. Voltage surges resulting from the lightning strokes were investigated using a simple model of a 12.8 kV distribution system with three feeder circuits. The model was developed for implementation on the McGraw-Edison Transients Analysis Program (METAP). It was found that a rate-of-voltage rise as high as 1,000 kV/ μ s is possible on overhead distribution systems as a result of a severe lightning stroke. If the converter transformer is fed through an underground cable, assuming the transformer is protected by an appropriate surge arrester, the voltage transient resulting from a lightning strike will not be as severe as it would be if the supply was through overhead lines. Because of lower cable surge impedance, the rate of voltage-rise upon entering the cable is reduced by approximately 80%.

Switching surges associated with energizing feeder capacitor banks were measured during field tests on two utility distribution systems. The transient overvoltages recorded during the switching of a 12 MVAR capacitor bank

ranged from 1.0 to 1.6 per-unit of the steady-state-phase-to-neutral crest voltage.

The effects of voltage transients on converter circuits are discussed in detail and corrective measures suggested. The effects are classified by various surge parameters such as rate of, voltage, rise, voltage magnitude and surge duration.

The instrumentation used for surge measurements on actual systems is described in Chapter 5. During the field tests, only capacitor switching operations could be staged. The instrumentation was designed to record these particular surges.

Section 6 provides guidelines for performing surge analysis to identify potential problems on the distribution system. The Transient Network Analyzer (TNA) and McGraw-Edison Transient Analysis Program (METAP) are briefly described. Also, results from the actual field tests are compared to the results obtained by analog and digital simulation. The simulated capacitor bank switching operations for one system resulted in transient overvoltages ranging from 1.0 to 1.45 per unit. The field test cases resulted in actual overvoltages as high as 1.49 per unit. Slightly more damping existed in the TNA simulations than appeared to be present during the field tests.

As a conclusion, this reference provides an excellent treatment of transient overvoltages on distribution systems. The results obtained here along with some from other references should provide excellent guidelines for surge protection of PV systems connected to the utility distribution system.

6. Application and Coordination of Reclosers, Sectionalizers and Fuses, IEEE Tutorial Course 80 EH 0157-8-PWR.

The purpose of this tutorial course was to address the topic of overcurrent protection of a distribution system in as complete a manner as possible. This will provide the utility engineer with a basic reference tool to aid in analyzing and providing adequate protection for the system. The course includes the basics of determining system parameters and calculating fault current magnitudes. This is followed by the basic nature, theory of operation, and application principles for fuses, reclosers, and sectionalizers normally used to provide overcurrent protection. Then, the coordination of these devices in series is detailed and a typical distribution system is presented to demonstrate the principles in a realistic situation. Finally, other specialized aspects of providing system protection and continuity are addressed.

With PV systems connected to the utility distribution system, the principles demonstrated in this tutorial must be followed closely to determine the impact on the system overcurrent protection.

7. Surge Protection in Power Systems,
IEEE Tutorial Course, #79 EH0144-6-PWR.

The objectives of this tutorial course were to present some of the essence of the voluminous material regarding: (a) concepts in surge phenomena, protection, and insulation coordination; and (b) specifically, modern procedures and practices in the application of surge protective devices in the following categories:

- (1) Station and station equipment.
- (2) Lines, cables, and connected equipment.
- (3) Underground and overhead distribution systems.
- (4) Rotating machines.
- (5) Gas insulated substations (GIS).

The material presented here relates to protection of the system against surges originating within the system itself. It is necessary to fully understand these practices before trying to implement an effective strategy for the protection of PV systems connected to the utility distribution system.

8. Investigate Protection of Electric Distribution Systems Containing Decentralized Generating Devices, RFP PEDS-19, Oak Ridge National Lab for Department of Energy.

This program is sponsored to investigate the adequacy of the electric utility industry's present protection and safety practices for electric distribution systems with dispersed production devices and to develop new protection and safety philosophies. Commercially available hardware will also be assessed and new hardware needs identified.

The scope of the various tasks is as follows:

- (1) Establish a benchmark by surveying the electric industry for their approach to distribution system protection and personnel safety with dispersed production devices.
- (2) Assess the impact of dispersed production devices on protection practice using reclosing as a policy, particularly considering reclosing on energized electronic sources. Identify any supplementary hardware (either presently available or that which could be developed) which should be considered. New hardware should have its functional characteristics defined as part of the study.

- (3) Develop a set of guidelines for recommended work practices, procedures and hardware needs, in the distribution system with dispersed production devices. Methods and devices for detecting the presence of dispersed production devices in the distribution system should be considered.
- (4) Investigate the economics of applying existing hardware to distribution systems, containing dispersed production devices, using present protection philosophies.
- (5) Establish strategies for properly coordinating protection among the substation, feeder, secondary transformer, and the production device. Give consideration to both technical and economic aspects. In developing these strategies, the size, location, and penetration of the dispersed production devices must be considered. The effects of islanding of an electric distribution system with dispersed production devices requires attention.
- (6) Assess the impact of backfeeding the distribution system on equipment.
- (7) Develop new protection philosophies for electrical distribution systems containing dispersed production sources. These approaches should be innovative with appropriate consideration given to digital schemes, particularly their reliability.
- (8) Identify new hardware needs when present equipment is inadequate to protect the system and the production device.

The following specific comments are offered regarding this RFP:

- (1) The thrust of the effort is the protection of the distribution system and not necessarily the dispersed generator itself.
- (2) Coordination between device protection and system protection is considered as well as various specific device protection scenarios.
- (3) Various scenarios and penetrations of DSGs will be evaluated, i.e., only PV sources on a feeder and a combination of PV, wind, etc.

As of this writing, the various contracts under this RFP have been awarded. The contractors selected are McGraw-Edison Company, General Electric, and Systems Control, Inc.

9. Impact of Dispersed Solar and Wind Systems on Electric Distribution Planning and Operations, Final Report, SCI for Oak Ridge National Lab, Report # ORNL-SUB-7662-1, February 1981.

The study conclusions are, that due to their high internal impedances, the current contribution from small dispersed generators would not be great enough to cause erroneous operation of utility's overcurrent devices.

These conclusions seem to be based on some very simple calculations for a limited penetration. Therefore, it may seem rather premature to come to such definitive conclusions. Some abnormal conditions (system resonances) might develop under which the fault current could be of great enough magnitude to adversely impact the time/current coordination of protective devices. Such cases need to be thoroughly investigated before any final conclusions are made.

10. Investigation of a Family of Power Conditioners Integrated into the Utility Grid, DOE Contract DE-AC02-79ET 29359 with Westinghouse Electric Corporation, Draft Final Report, January 1981.

The study points out the need for coordinating converter ac fault protection with existing devices in the residence and the utility network. To protect the converter's internal parts, converter ac fault clearing or other protective action must be much faster than normal ac protective devices.

The exposure voltage of residential circuits to voltage surges is generally within a range of 2-5 kV. The wiring breakdown limit is typically 6-8 kV. For acceptable reliability, the study recommends that the conversion equipment be designed to withstand the same surge levels as the wiring.

For current source converters, this is done only by applying suitable surge limiting devices (selenium, zinc oxide or a silicon carbide spark gap) at the converter side of the isolation transformer and by using thyristors with voltage ratings higher than the peak discharge voltage of the surge limiting device used. The current sourcing inductor must also be designed to withstand that peak discharge voltage. For a voltage-sourced converter, no protection is suggested provided the total tie impedance is large enough.

G. GUIDELINES/STANDARDS

1. Standard Voltage Values for Preferred Transient Insulation Levels. ANSI C92.1-1971
2. Guide for Application of Valve Type Surge Arresters for AC Systems. ANSI C62.2-1978

3. Surge Arresters for AC Power Circuits.
ANSI C62.1-1975

The foregoing three standards relate to the proper surge protection and to selection of insulation withstand levels for ac systems.

4. IEEE Guide for Protective Relaying of Utility-
Consumer Interconnections. ANSI C37.95-1974

This guide was prepared to aid in the effective and uniform application of fuses, relays, and associated switching equipment located at the point of interconnection between the utility and the consumer electrical systems.

Descriptions of the various devices, definitions of terms and references to other technical publications were included to make the guide useful to relay engineers and to other technical people not intimately familiar with the art of relaying. It includes examples for relaying of typical installations, with and without consumer generation and with service from utility radial or loop feeders.

The protection principles presented in this guideline should be helpful in designing protection schemes for distributed PV systems connected to the utility.

5. Standards for Operating Reliability,
California Public Utilities Commission
Draft Report, Chapter 14.

This draft report was prepared as a result of FERC Section 292.308 which requires that any state regulatory authority (with respect to an electric utility over which it has rate-making authority) or a non-regulated electric utility may establish reasonable standards, to ensure system safety and reliability of interconnected operation.

The PUC staff recommendation regarding protection is given below.

The following functional standards shall be observed by each Qualifying Facility (QF) when generating in parallel with an electric utility:

- (1) Sense and properly react to utility failures/malfunctions.
- (2) Assist the utility in maintaining system integrity and reliability.

- (3) Protect the safety of the public and utility personnel.

All QFs shall provide protection against the following adverse conditions that can cause electric service degradation, equipment damage, and harm to others:

- (1) Prevention of inadvertent and unwanted reenergization of a utility dead line or bus.
- (2) Interconnection while out of synchronization.
- (3) Overcurrent.
- (4) Utility system load unbalance.
- (5) Ground faults.
- (6) Generated ac frequency outside permitted safe limits.
- (7) Voltage generated outside permitted limits.
- (8) Poor power factor.

The utility may require medium and large QFs, 100 kW and above, to have, in addition to the protection listed above, overcurrent protection, utility system load unbalance protection, and a suitable power factor. An alternate would be a power factor compensation up to its nameplate generation capacity.

Should the interconnection requirements be simplified for induction generators and other utility line-commutated inverters? It is believed that these generators might excite each other, or various inductive-capacitive line conditions could excite and cause inductive generators to continue operating, if that part of the circuit separates from the utility. Thus, these types of generators should not be given any special treatment.

These are only general guidelines and are not based on any detailed technical analyses. It is hoped that each issue will be examined in detail before any specific standards are formulated.

6. Interconnection Facilities and Facilities
for Operating in Parallel, American Public
Power Association (APPA), Final Report,
September 12, 1980.

This paper was prepared by a five-member subcommittee of the APPA Cogeneration Task Force. It was primarily intended to provide an overview, with some detail, of the technical aspects of interconnecting and operating in parallel with cogeneration and small power production facilities (QFs). This was required under the final rule issued by the Federal Energy Regulatory

Commission (FERC) on February 19, 1980, regarding the implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978.

Some technical considerations of interconnected operations with QFs were not addressed in this paper. These include, for example, the impacts of increasing numbers of QFs connected to a single or multiple circuit(s) of a utility and the impacts of more than one QF connected in series to a utility.

The guidelines regarding protection were:

- (1) Any ac QF system should have fault detecting equipment to disconnect under fault conditions. Without the required protection (fault and overcurrent), the total electrical system of the QF is a hazard.
- (2) Any dc system with a line commutated inverter should be required to shut down upon loss of utility line voltage. In addition, the line commutated inverter must have a device to completely isolate the inverter from the utility system if the utility voltage drops 20%; for example, 96 V line-to-ground in the case of nominal 120-V service.
- (3) Self-commutated QFs may be acceptable if they are adequately protected with over/under voltage relays, frequency relays, and automatic synchronizing relays and if they are prevented from paralleling with the utility unless the utility line is energized. They should also shut down or disconnect from the utility system when the utility's interconnected line becomes deenergized.
- (4) The National Electric Code (NEC) ART 230, 240, and 280 and local building codes will have jurisdiction on the usage and location of protective devices. The supplying utility may also have specifications concerning these devices.
- (5) The addition of a voltage regulator to regulate QF voltage output at nominal +5% may be required to prevent over/under voltage from entering the utility distribution system. Protection for over/under voltage on the utility system is very important to prevent damaging and shortening the life of customer equipment.
- (6) Electric system characteristics may be affected by the fault current of the QF. The fault current, previously supplying only the utility, now becomes the sum of that available from the utility and from the QF. This additional current, however, probably will not preclude the use of the protection (fuses) normally used on supply lines. However, if directional relaying is used, the addition of the QF may require modification of the relaying scheme for the relays to perform properly.

7. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

This reference describes the TVA proposed policy for encouraging dispersed power production in the Tennessee Valley region and an interim program and guidelines to assist TVA and its power distributors in the implementation of this policy. The policy, program, and guidelines encompass cogeneration and small power production facilities included under Sections 201 and 210 of the Public Utilities Regulatory Policies Act of 1978.

The guidelines for protection are as follows:

(1) Fault Protection

- (a) Adequate protection facilities shall be provided by the owner to protect the line(s) connecting the production facility to the electric system from faults originating from the production facility. This includes primary fault disconnecting switchgear and secondary relaying and control circuitry.
- (b) It shall be the responsibility of the owner to provide adequate protection of its production facility from fault currents originating in the electric system because of a fault in the production facility.

(2) Overvoltage and Undervoltage

- (a) It shall be the responsibility of the owner to provide adequate protection or safeguards to prevent damage to the connecting electric system caused by overvoltage originating from the operation of the production facility.
- (b) It shall be the responsibility of the owner to provide adequate protection of its production facility from inadvertent overvoltages originating on the connecting electric system.
- (c) It shall be the responsibility of the owner to provide facilities which adequately to prevent the production facility from being damaged by under voltage conditions on the connecting electric system.

(3) Synchronization

- (a) The owner shall provide adequate facilities for the proper synchronization of its production facility with the connecting electric system such that synchronization is accomplished without causing undesirable currents, surges, or voltage dips on the connecting electric system.
- (b) The owner shall provide means for properly disconnecting the production facility from the connecting electric system for system line interruptions and for the proper resynchronization of the production facility following such interruptions.

8. San Diego Gas and Electric Company, Protection and Operation Guidelines for Cogenerators and Small Power Producers, Preliminary Draft Submitted to California PUC.

The excerpts from this draft pertaining to the protection of generators less than 100 kW are:

- (1) The customer will be required to provide suitable devices to ensure adequate protection for the conditions as follows:
 - (a) All faults on the customers system involving phase and/or ground.
 - (b) Faults on the SDG&E system (for some utility system faults, clearing may be sequential with customer's separation due to excessive backfeed or undervoltage conditions after the utility system has cleared).
 - (c) Prevent backfeed or start-up of a customer's generator(s) into a dead SDG&E bus. This condition can be waived where backfeed from the customer's generation is not possible.
- (2) As a minimum, the following customer protective devices are required to effect connection and separation of the utility and customer systems.
 - (a) Individual phase overcurrent trip devices.
 - (b) Undervoltage trip devices.
 - (c) Underfrequency trip devices.
 - (d) Synchronizing or equivalent controls to ensure a smooth connection with the utility system.
- (3) The requirements listed in (2) are based on SDG&E's forecast that there will be a relatively small amount of customer generation vs. load for any particular line on the utility system. If a heavy saturation of small power production on some line(s) does occur in the future, the customer may be required to provide additional protection at that time. When an induction generator is installed, the phase overcurrent trip devices may be waived. Permission to waive these devices will be given only after a check of the supply circuit (for capacitance) was made and it was determined that the customer's generation will not be able to backfeed the SDG&E system.
- (4) The customer shall not reconnect his generator after a protective device trip unless his system is energized from the utility source or unless he has isolated his system from the utility.

9. Operating, Metering, and Protective Relaying Requirements for Parallel Operation by Small Cogenerators and Power Producers, 100 kW or Less, Pacific Gas & Electric Company, Draft Submitted to California PUC, September 1980.

This guideline is one of the few giving clear, single-line diagrams of the protection requirements for cogenerators connected to the system. The excerpts from these guidelines pertaining to protection are:

- (1) Minimum protection requirements must be provided for safe and reliable parallel operation of both the seller's equipment and PG&E's electric system. While most commercially available generators are equipped with some protective and control devices, additional equipment may be required to permit parallel operations with the PG&E system depending upon the type and size of unit.
- (2) All generating units must have a generator circuit breaker capable of interrupting short circuit currents at its location. The generator circuit breaker must be equipped with thermal-magnetic overcurrent on each phase as well as undervoltage release and solenoid tripping accessories. Additional relaying must be provided to trip the generator circuit breaker for safe isolation or shut down in the event the voltage or frequency at the interconnection point is not within PG&E's normal operating tolerances. Normally, an overvoltage relay set at 120% of normal with no time delay is required. Under- and overfrequency relays set at 58 Hz and 62 Hz, respectively, are required with one second time delay. Frequency relays are not required for generators connected to the PG&E system through a solid state inverter which is line-commutated. For generating units over 40 kW, an undervoltage relay set at 80% of normal, with ten second time delay, is required in addition to the frequency and overvoltage relays mentioned above.

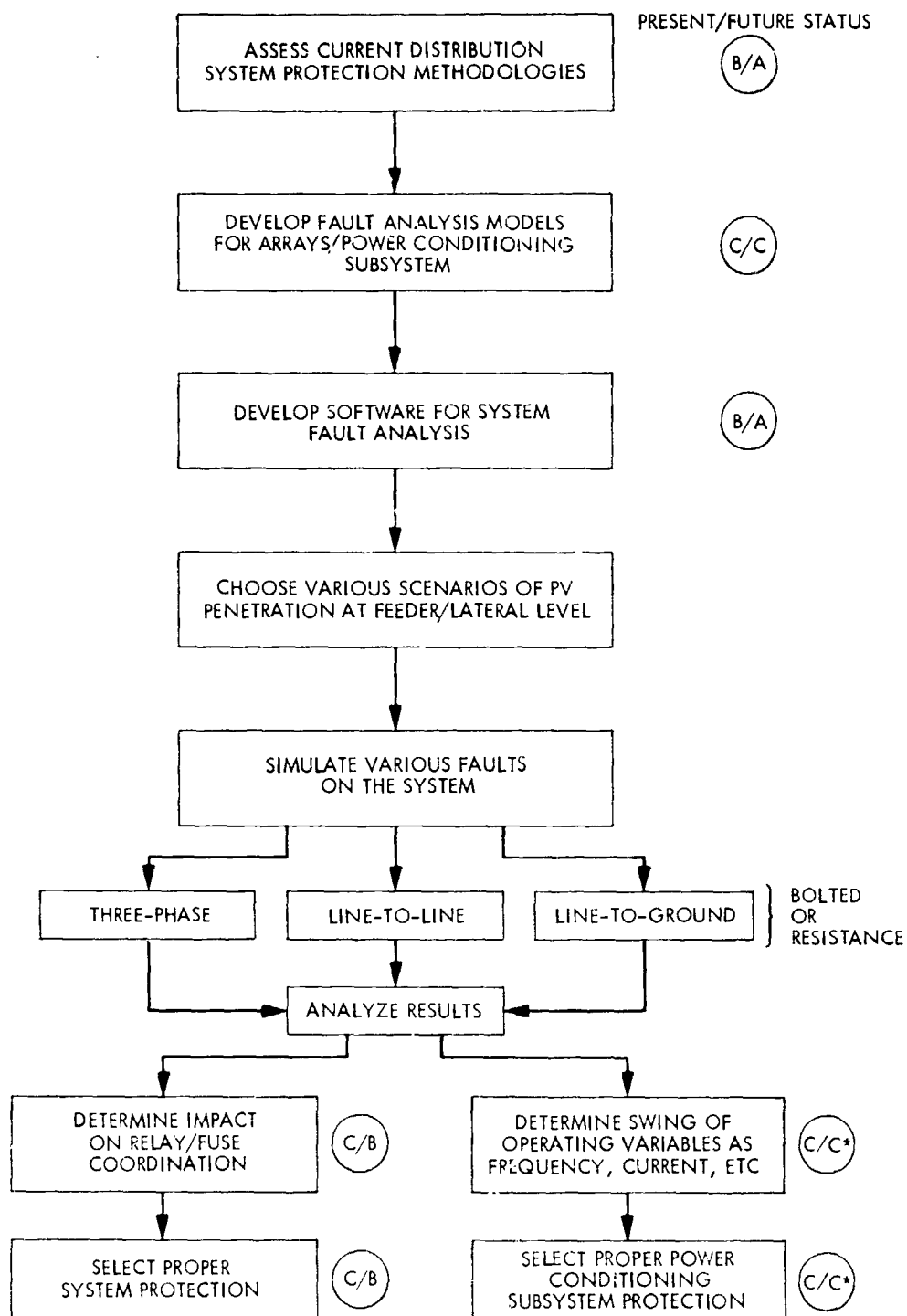
H. CONCLUSIONS

- (1) There is a substantial body of knowledge on the problem of surge protection for devices and distribution systems. The undesirable effects of voltage surges on converter equipment seem to be well known. It is thought that proper surge protection for PV systems can be provided based on the existing guidelines and standards for the surge protections of systems and appliances.
- (2) Although the phenomenon of resonant overvoltages is well known and understood, it is very system-specific. Some preliminary guidelines are available for avoiding such resonances, but they are more 'rules of thumb' than specific recommendations.

- (3) Some preliminary studies indicate that the distributed PV system will have very little impact on the coordination of protective devices on the distribution system. However, the scope of these studies was very limited. More analysis is needed to substantiate this point of view.
- (4) The protection of the Power Conditioning subsystem itself is an important issue; not much has been done about it. In the conceptual design of power conditioners for PV applications (see Appendix B, Bibliography), specifications for protection such as under/over voltage, under/over frequency, etc., have been provided. However, it is felt that the selection of these protective devices should be based on a thorough system analysis of the operating environment in an actual utility interactive mode. The need to coordinate this protection with the utility is highly important.
- (5) Some guidelines are available from the utilities regarding protection requirements for dispersed generators. However, these guidelines impose only general requirements on the dispersed generator for connection to the utility and may not offer total protection to it.

1. RECOMMENDATIONS

To solve the outstanding issues a plan of action is recommended, which is shown in the flow-chart in Figure 2-6. Some efforts have been made or are currently being made (by organizations such as DOE, EPRI, etc.) to address the various problem areas outlined within this flow-chart. The status of these efforts is summarized in Table 2-1. Column I describes the problem area. Column II gives the present status with a letter symbol. It also represents a worst-case future status if none of the proposed activities ever take place. Column III gives an optimistic projection of the future status. The future status is based on the premise that all the currently planned and proposed DOE (EES & PV) studies take place as scheduled. Column IV cites the references discussed in the body of the section which are responsible for any change in the status of the various problem areas.



*THE STATUS OF THESE ISSUES MIGHT BE UPGRADED IN THE FUTURE, REFLECTING TASKS OUTLINED IN A NEW TECHNOLOGY INTEGRATION PROGRAM PLAN BEING DEVELOPED BY DOE/EES AND NOT AVAILABLE AT THE TIME OF PUBLICATION.

Figure 2-6. Proposed Plan of Action to Resolve the "Protection" Issue

Table 2-1. Protection: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Assessment of distribution protection practices.	B	A	8
Development of fault analysis models for arrays and Power Conditioning Subsystem.	C	C	-
Development of software for fault analysis of distribution systems with dispersed generation.	B	A	8
Determination of the swing of various operating variables during faults with PV connected.	C	C	-
Determination of the impact on relay/fuse coordination.	C	B	8
Selection of proper Power Conditioning Subsystem protection	C	C	-
Selection of proper system protection	C	B	8
<p>A The issue is completely resolved or can be resolved when based on available knowledge.</p> <p>B Much is known or documented, but the issue is not totally resolved.</p> <p>C Very little is known or documented.</p> <p>D Nothing is known or documented.</p>			

SECTION III

STABILITY

A. INTRODUCTION

Stability, in the conventional power system sense, refers to the ability of the system to maintain synchronous operation after a disturbance. In the control theory sense, it refers to the ability of the control system to direct the system to a new desired equilibrium state following a disturbance or any external stimulus. (Note: These are not rigid definitions, but are used here to convey the sense in which stability is being used. For rigid definitions, please see Reference 1 and text books on control theory.)

In the context of the present discussion, stability can be divided as shown in Figure 3-1. Each category is discussed below.

B. SOURCE STABILITY

1. Definition

Source stability is defined as the ability of an individual PV system connected to the utility system to maintain operation without large fluctuations in voltage, power, etc., such as might result from improper controls. The assumption here is that the PV system power rating is far less than the size of the utility.

2. Risk

Any such fluctuations in output parameters could cause nuisance tripping of the PV source following a disturbance. In some cases, it could also cause damage to the PV system.

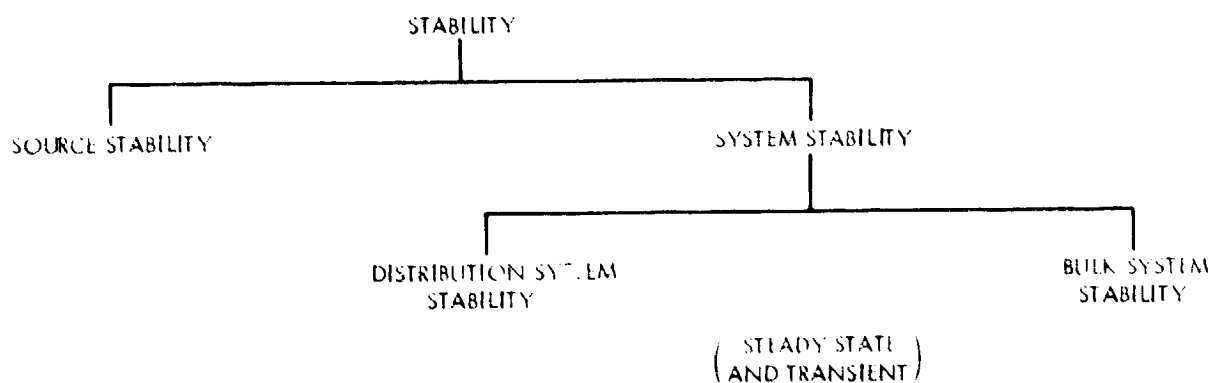


Figure 3-1. Stability Categories

3. Discussion

In all PV systems, it is highly desirable to extract all the available energy out of the array at each instant. This implies that the array must be operated at its maximum power point (or very near it) based on its voltage-current characteristics. This is achieved by a sophisticated control scheme that constantly tracks the various operating parameters and adjusts the PV system operating point so that the maximum power transfer is obtained. Besides the maximum power tracker control loop, other control loops, such as the one for reactive power control, may be employed within the PV systems.

It is highly important that all these control loops operate in a stable mode under the wide fluctuations in operating parameters which can be expected in a utility interactive operation. These fluctuations could either be array specific, such as changes in available insolation, array temperatures, etc., or utility specific, such as changes in voltage, frequency, etc.

The transfer functions of the various elements of the control loops would determine the stability of the PV systems under the wide range of operating parameters enumerated above. If the PV systems are found to be unstable or marginally stable under certain operating conditions, it may be necessary to modify the control systems to achieve a stable operation.

At this stage, it should be clear that source stability refers to the interaction of a single PV system with the rest of the utility system and not to the interaction between many PV systems and/or the utility.

C. DISTRIBUTION SYSTEM STABILITY (BOTH TRANSIENT AND STEADY STATE)

1. Definition

Distribution system stability is the ability of the many distributed PV systems and other DSGs (such as wind generators, fuel cells, batteries, etc.) connected to a single distribution substation to maintain synchronous operation under the wide range of disturbances occurring on the system. (See Reference 1 for a detailed explanation of transient and steady state stability.) The main assumption here is that any disturbance generated (such as tripping of a lateral or a feeder) as a result of any undesirable dynamic interactions between these various sources is confined to a feeder or a distribution substation and does not impact the bulk system.

2. Risk

Any undesirable interaction between various PV systems and DSGs connected to the same distribution system could cause nuisance tripping at the lateral, feeder or substation level causing unnecessary outages to the customers. It could also result in damage to customer equipment connected to the system.

3. Discussion

Technology is being developed for other DSGs including wind, fuel cells, batteries, cogeneration, low-head hydro, etc. These devices are eventually expected to be integrated into the utility system. In fact, some of these technologies such as low-head hydro, wind and cogeneration are probably ahead of PV in terms of technology and commercial readiness. It is probably safe to assume that a future electrical distribution system will have a multitude of these sources connected to the system and in many cases, to the same distribution feeder. This study was concerned only with specific problems with PV integration. However, it is highly important that all the PV sources operate reliably in conjunction with the other DSGs on the system.

As the operating characteristics of these different types of sources differ greatly, it is necessary to evaluate the dynamic interaction of the various sources with each other and with the utility system. It is quite possible that any undesirable interactions between these various sources would have a considerable impact on the design of the Power Conditioning Subsystem.

D. BULK SYSTEM STABILITY (BOTH TRANSIENT AND STEADY STATE)

1. Definition

See Reference 1 below. The only disturbances of concern are the ones specifically attributable to the PV systems.

2. Risk

Any concern with bulk system stability could limit the maximum PV penetration on any given utility system.

3. Discussion

For a stable system operation, the many synchronous generators connected to the system have to operate in mechanical synchronization. Any sudden disturbance on the system can cause one of the following end effects:

- (1) The system will settle down to a new equilibrium state characterized by a new set of power flows within the network.
- (2) The system will lose synchronization resulting in a chain reaction of line trippings and eventual system collapse.

The present power systems are so designed and operated that it would take a severe disturbance (loss of a big generating unit, fault on a loaded transmission line, etc.) to render the system unstable. System instability is something dreaded by the utilities. It can cause total system breakdown before any protective action can be taken. The historic blackout in New York City is an example.

With PV sources connected to the grid, system stability may not be a major concern until the PV penetration becomes quite high (5-10%). At that level of penetration, it would probably be more of a concern for large-scale central station plants than small-scale distributed systems. The obvious reason is that big plants can generate a larger disturbance on the system than small scale units. An example of a disturbance is a rapidly passing cloud cover which can drive the output power of the affected PV sources to a low value very rapidly. This is analogous to the loss of a generating unit in a utility with conventional generating sources. The resulting loss of power, if large enough in magnitude, could cause stability problems. However, this problem is system-specific and may have to be investigated on a one-to-one basis.

F. REFERENCES

1. "Proposed Terms and Definitions for Power System Stability," IEEE Task Force on Terms and Definitions, Power Systems Engineering Committee, Paper #81 WM 082-7, IEEE-PES Winter Meeting, Atlanta, Georgia, February 1-6, 1981.

This paper defines terms in pursuing electric utility industry uniformity and understanding in the analysis of power system stability. Although most of the terms are not new, they have been defined precisely. In doing so, the historical use of the terminology was considered.

One interesting suggestion presented was to eliminate the term dynamic stability which many referred to as the stability beyond the usual 1-s period covering the transient region. The new definition for transient stability is not time constrained.

2. Merrill, W. C., et al, Performance and Stability Analysis of a Photovoltaic Power System, Report No. DOE/NASA/1022-78/30.

This is a simulation study of the dynamics associated with a 10-kW PV system interconnected to a utility. A detailed model was developed of all components in the system including the inverter and solar arrays. The results indicated that, under good insolation conditions, stable operation was obtained. However, under low insolation conditions (20 mW/cm^2) limit cycle operation was encountered in the controls of the inverter. Thus, for interconnected operation, careful consideration to control parameters and feedback design must be shown to prevent undesirable operation.

3. Pickrell, Roy L., et al, An Inverter/Controller Subsystem Optimized for Photovoltaic Applications, Proceedings of the Thirteenth IEEE PV Specialists Conference, pp. 984-991, 1978.

This study shows the development and analysis for a force commutated converter designed exclusively for a PV/utility application. The requirements were threefold:

- (1) A power system controller that can continuously control the solar array operating point at the maximum power level based on variable solar insolation and cell temperature.
- (2) An inverter that can operate at high efficiency at rated load and yet have low losses at light loading conditions.
- (3) An inverter that operates (at a level designated by the power system controller) when connected to the utility.

The simulation of the entire system showed good operating characteristics. Yet, at low insolation values, limit cycle operation appeared as in the previous study.

It seems that care must be taken in the design of the controllers used to avoid this unwanted problem.

4. Beck, et al, "A Computer Study of Battery Energy Storage and Power Conversion," IEEE Transactions on Power Apparatus and Systems, July/August 1976.
5. Fairchild, B. T., et al, "Hybrid Simulation of Fuel Cell Power Conversion Systems," IEEE Transactions on Power Apparatus and Systems, pp. 1329-1336, July/August 1977.

These two papers were combined because they deal with similar subjects in a similar manner. The studies use the hybrid computer to program the detailed models of the devices to be analyzed and run transient studies. The papers analyze force commutated and line commutated converters.

For force commutated converters, there is dc current limitation due to the inherent characteristics of the inverter. Also, since there was no power factor control, reactive power compensation is required. Finally, under utility disturbances, large dc current transients were encountered.

For line commutated converters, there was a dc current runaway condition following ac faults. This was caused by the low internal impedance of the voltage source. The study noted the need for a dc interruption device, and the need for reactive power compensation. However, outside of the fault condition, the line commutated converter was fairly insensitive to utility disturbances. Thus, the line commutated converter was recommended for large battery and energy storage installations.

6. Impact of Storm Fronts on Utilities with Wind Energy Conversion Systems (WECS) Arrays, Michigan State University, Report No. C00/4450-79/2.

This study is a good step in understanding the difficulties a utility has with a large penetration of intermittent sources. The study presents the results from two types of farms: (1) coastal: a broad, shallow field, usually only a couple of rows deep; and (2) midwestern: a square farm. The coastal farm will have larger transients during storm fronts because more generators are affected at any given point in time. The midwestern farm has a more staircase nature from the fewer number of generators affected.

Under the conditions studied, the coastal farm caused the Automatic Generation Control (AGC) System to saturate, thus allowing a large disturbance in the frequency. In all, a 7.5% change in generation was required within 10 min.

For the midwestern farm, the staircase nature of the WECS output caused cycling of the nuclear plants. This is a highly undesirable mode. Because the nuclear units are designed as base load units and not cycling units, their efficiency falls off as a cycling plant.

7. Ewart, Donald N., and Schultz, Richard P., "Use of Digital Computer Simulations to Assess Long-Term Power System Dynamic Response," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-94, No. 3, May/June 1975.

This paper describes the use of typical long-term dynamic codes to show the effects of controls. It also shows the benefits of event simulation: what occurred, when, and why. Such tools are needed to study the dynamic interaction between PV systems and the rest of the utility.

8. Photovoltaic Transient Analysis Program, BDM Corporation, Report No. SAND 78-7083, Sandia National Lab.

This program allows the user to specify the type of array and peripheral equipment to be studied. It has detailed models for the PV array, allowing for parallel and series connections; for the solar cells, using the Ebers-Moll model; and heat transfer characteristics. Unfortunately, very little detail is shown in the inverter, its controls, or the other auxiliary equipment on site.

Once the models have been constructed, the user can perform steady-state, transient, and small excursion ac analysis.

9. Statement of Work for Dynamic Simulation of Dispersed, Grid-Connected Photovoltaic Power Systems, 62-4092, Sandia National Lab, December 1980.

The basic objective of this RFP is to study the dynamic interaction of distributed PV systems with the electric utility grid. The primary emphasis of the study is the behavior of PV systems at the utility interface. The study purpose is not to model system disturbances such as lightning and switching surges and the resulting behavior in the microsecond time domain. Neither is the purpose to model electrical dynamics for longer than several seconds.

There are four basic tasks enumerated in the Statement of Work. They are as described below:

- (1) Task I: PV System Model Development. This task will develop the appropriate dynamic electrical models for a set of representative PV systems. The typical sizes of power conditioning equipment to be modeled are 5 kW, 240 V single-phase, 10 kW, 240 V single-phase, and up to 250 kW, 480 V three-phase. These could include self-commutated and line-commutated as well as advanced control techniques such as high frequency conversion and ferroresonant transformer control.
- (2) Task II: Distribution System Simulation. After the PV system models have been developed for Task I, each PV system will be simulated on representative distribution systems. Not only will each PV system be modeled on several distribution circuits, but several types of PV systems will be modeled simultaneously on the circuits. The dynamic simulation would include both low and high PV system penetrations in the distribution circuit, such as 0-10% at the feeder, 0-25% at the primary distribution substation, and 0-100% at the secondary distribution system.
- (3) Task III: Transmission System Simulation. Task III will involve extrapolation from the individual models described in Task I and the distribution network simulation performed in Task II. This

will represent the collective effect of significant penetrations of PV systems on the dynamic stability of the utility generation and transmissions systems.

- (4) Task IV: Interpretation of Simulations. This task will summarize the findings from the other tasks and provide a physical description of the nature and intent of anticipated problems. It is also intended to provide recommendations for circuit modification and control system changes to overcome any problems. Also, it would identify the percentage of PV penetration where problems begin to appear for various inverter models in the dynamic interaction with the electrical utility grid.

There is a major question on whether the proposed study can achieve all its objectives within the resources allotted. However, it is an important step to better understand the dynamic interaction between the PV system and the utility grid.

10. Interaction Between an OTEC Power Plant and a Power Grid, Ongoing DOE/EES Contract with ERDI (Energy Research and Development International).

This study investigates the interaction of an OTEC power plant with the Puerto Rico Electric Power Authority electrical power system. The project would develop suitable OTEC models for both steady-state and dynamic analysis and use standard computer codes to perform analysis.

F. STANDARDS/GUIDELINES

None exist on this particular issue.

G. CONCLUSIONS

- (1) Although the problem of bulk system stability is well understood, very little is known about the stability problems of dispersed PV systems. Some initial studies with individual PV systems show that stability problems might develop.
- (2) Little is known about the dynamic interaction of many PV systems with each other and with the utility system. Because future distribution systems might also contain other DSG, the dynamic interaction of dispersed PV systems and DSG also must be determined.
- (3) Techniques to determine bulk-system stability are well established. Some modifications may be needed to study the dynamic impact of PV systems on bulk-system operation.

H. RECOMMENDATIONS

Figure 3-2 presents a recommended plan of action, in flow chart form, for the resolution of the various problem areas. Table 3-1 gives the status of the various areas.

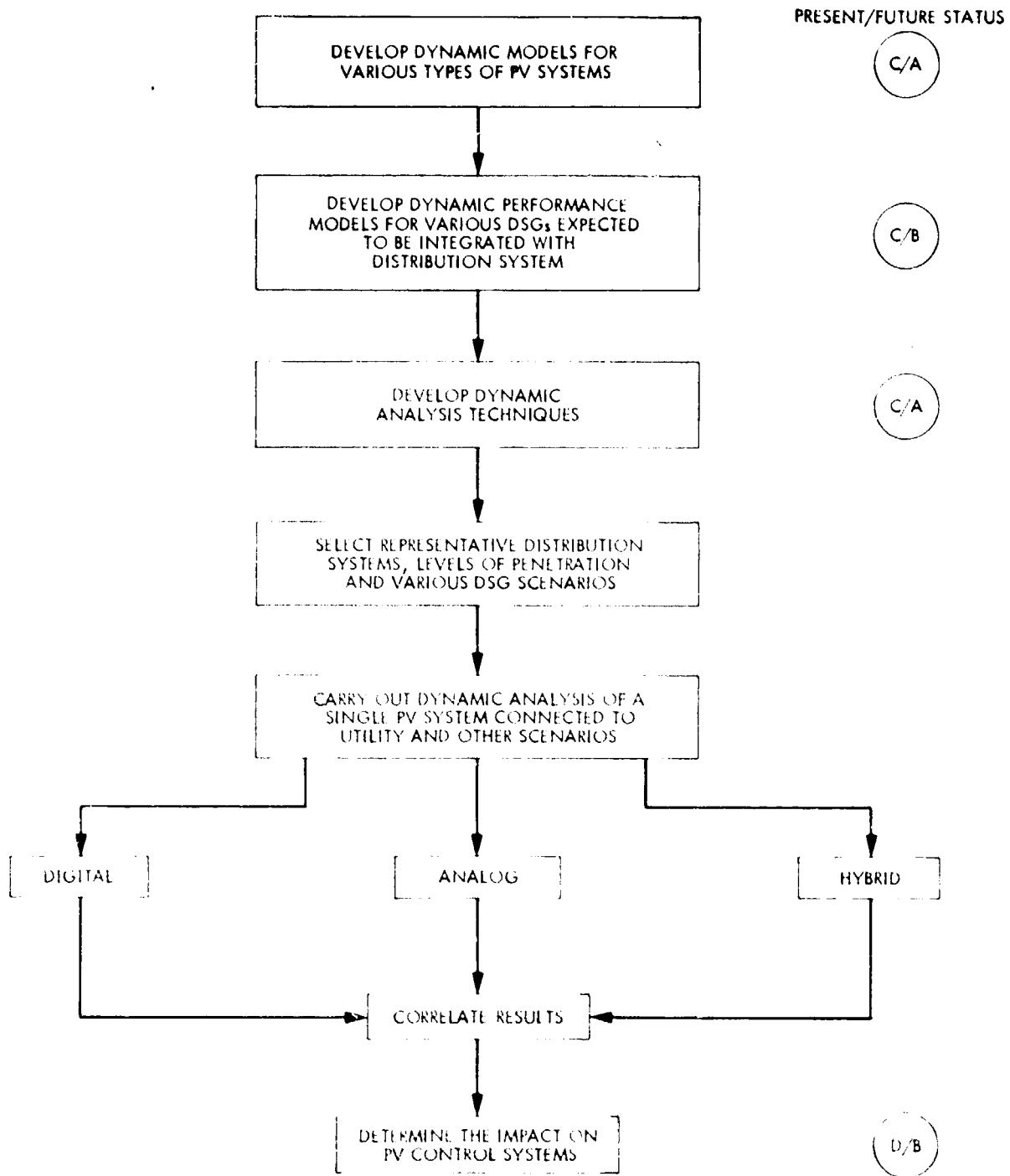


Figure 3-2. Flow-Chart Showing a Recommended Plan of Action to Resolve the "Stability" Issue

Table 3-1. Stability: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Dynamic Models of PV Systems	C	A	9
Dynamic Models of DSGs	C	B	9,10 ^a
Dynamic Analysis Techniques	C	A	9
Impact on PV Control System	D	B	9

^aDOE also has many ongoing research activities in the area of wind system modeling.

- A The issue is completely resolved or can be resolved when based on available knowledge.
- B Much is known or documented, but the issue is not totally resolved.
- C Very little is known or documented.
- D Nothing is known or documented.

SECTION IV

SYSTEM UNBALANCES

A. INTRODUCTION

1. Definition

System unbalance is defined as the unbalance generated in system voltages and currents due to unequal loading in the various phases caused by single phase PV systems.

2. Risk

Excessive unbalance can cause problems with system operation, component overheating, and nuisance tripping of protective devices. It may, therefore, limit the maximum allowable size of single-phase PV systems and also the level of penetration on a distribution feeder.

3. Discussion

Almost all residential PV systems are expected to be single-phase systems. Any unequal distribution of the sources on the three phases will result in unbalanced system operation (unequal voltages and currents in the three phases). Some of the undesirable effects of unbalanced system operation are overheating of system components, incorrect operation of voltage regulation equipment, propagation of triplet (frequency multiples of 3) harmonics on the lines which otherwise would be cancelled out in a balanced operation, nuisance tripping of protective devices (see Appendix C for utility practices), and excessive negative sequence voltage which would cause motor overheating. With PV sources connected to the system it may be quite hard to avoid unbalance, unless there was a uniform physical distribution of PV sources in the system and all the sources were generally of the same size. A nearly balanced operation is achieved on current distribution systems by equally distributing the homes on the various phases because the diversified load demands of homes in a particular neighborhood are almost identical.

B. REFERENCES

1. IEEE Recommended Practice for Electric Power Distribution for Industrial Plants, IEEE Std 141-1976 (Red Book).

Chapter 3 of this IEEE standard deals with phase unbalance caused on four-wire utility primary distribution systems due to single phase distribution.

The simplest method of expressing the phase voltage unbalance is to measure the voltage in each of the three phases:

$$\text{Phase voltage unbalance} = \frac{\text{maximum deviation from average phase voltage}}{\text{average phase voltage}}$$

The amount of voltage unbalance is better expressed in symmetrical component form as:

$$\text{Voltage unbalance factor} = \frac{\text{negative sequence voltage}}{\text{positive sequence voltage}}$$

When unbalanced phase voltages are applied to three-phase motors, the phase voltage unbalance causes additional negative-sequence currents to circulate in the motor, increasing the heat losses in the rotor.

Table 4-1 shows the increased temperature rise which occurs for specified values of phase voltage unbalance for U-frame and T-frame motors.

The table indicates that, where the phase voltage unbalance exceeds 2 percent, the motor is likely to become overheated if it is operating close to full load.

Some electronic equipment, for example, computers, may also be affected by phase voltage unbalance of 2 or 2 1/2 percent. The general recommendation is that single-phase loads should not be connected to three-phase circuits supplying equipment sensitive to phase-voltage unbalance. A separate circuit should be used to supply this equipment.

Table 4-1. Increased Temperature Rise of Motors Under Phase Voltage Unbalance

Motor Type	Load	Percent Voltage Unbalance	Percent Added Heating	Insulation System Class	Temperature Rise (°C)
U-Frame	Rated	0	0	A	60
	Rated	2	8	A	65
	Rated	3 1/2	25	A	75
T-Frame	Rated	0	0	B	80
	Rated	2	8	B	86.4
	Rated	3 1/2	25	B	100

2. Electric Utility Engineering Reference Book,
Vol. 3, Distribution Systems, Westinghouse Electric Corporation.

Chapter 2 of this book describes some equations to determine voltage unbalance factor in three-phase circuits.

The voltage unbalance in a three-phase, three wire system in which the zero sequence voltages are zero is given by:

$$\frac{|V_2|}{|V_1|} = \sqrt{\frac{\frac{a^2 + b^2 + c^2}{6} - 2 \left[\frac{s(s-a)(s-b)(s-c)}{3} \right]^{1/2}}{\frac{a^2 + b^2 + c^2}{6} + 2 \left[\frac{s(s-a)(s-b)(s-c)}{3} \right]^{1/2}}}$$

where

V_2 = negative sequence voltage

V_1 = positive sequence voltage

a, b, c = the absolute values of respective line-to-line rms voltages and

$$s = \frac{a + b + c}{2}$$

The unbalance in voltages to neutral of a single-phase, three-wire system is usually given as the difference in line-to-neutral voltage. This is given by the following equations:

Single-phase voltage unbalance

$$\frac{|V_2|}{|V_1|} = \left(\frac{|V_{1N}| - |V_{2N}|}{\frac{V_{1-2}}{2}} \right), |V_{1N}| > |V_{2N}|$$

where

V_{1N} and V_{2N} = rms voltages to neutral of lines 1 and 2, respectively

V_{1-2} = normal rms line-to-line voltage

C. GUIDELINES/STANDARDS

Other than the guidelines outlined in Reference 1 above, no other guideline or standard could be identified.

D. CONCLUSIONS

- (1) The effect of voltage unbalance on electrical motors (induction) seems to be well documented. The limit on phase voltage unbalance is about 2%.
- (2) Not much literature can be found on the effects of unbalance on other three phase appliances and equipment.
- (3) The procedure to calculate voltage and current unbalance in a system (symmetrical components) is well established. However, the inputs needed (voltages, currents, impedances etc.) may be hard to obtain.

E. RECOMMENDATIONS

The recommended plan of action for resolving this issue is presented in Figure 4-1. The status of the various problem areas is presented in Table 4-2.

Table 4-2. System Unbalance: Status of Problem Areas

Problem Area	Present Status	Future Status	Reference Numbers
Determine limits on unbalance factors	C	C	-
Develop steady state models of PV systems	B	B	-
Distribution load-flow software	B	A	-
Assess impacts of unbalanced system operation on PV systems	D	D	-

A	The issue is completely resolved or can be resolved when based on available knowledge.
B	Much is known or documented, but the issue is not totally resolved.
C	Very little is known or documented.
D	Nothing is known or documented.

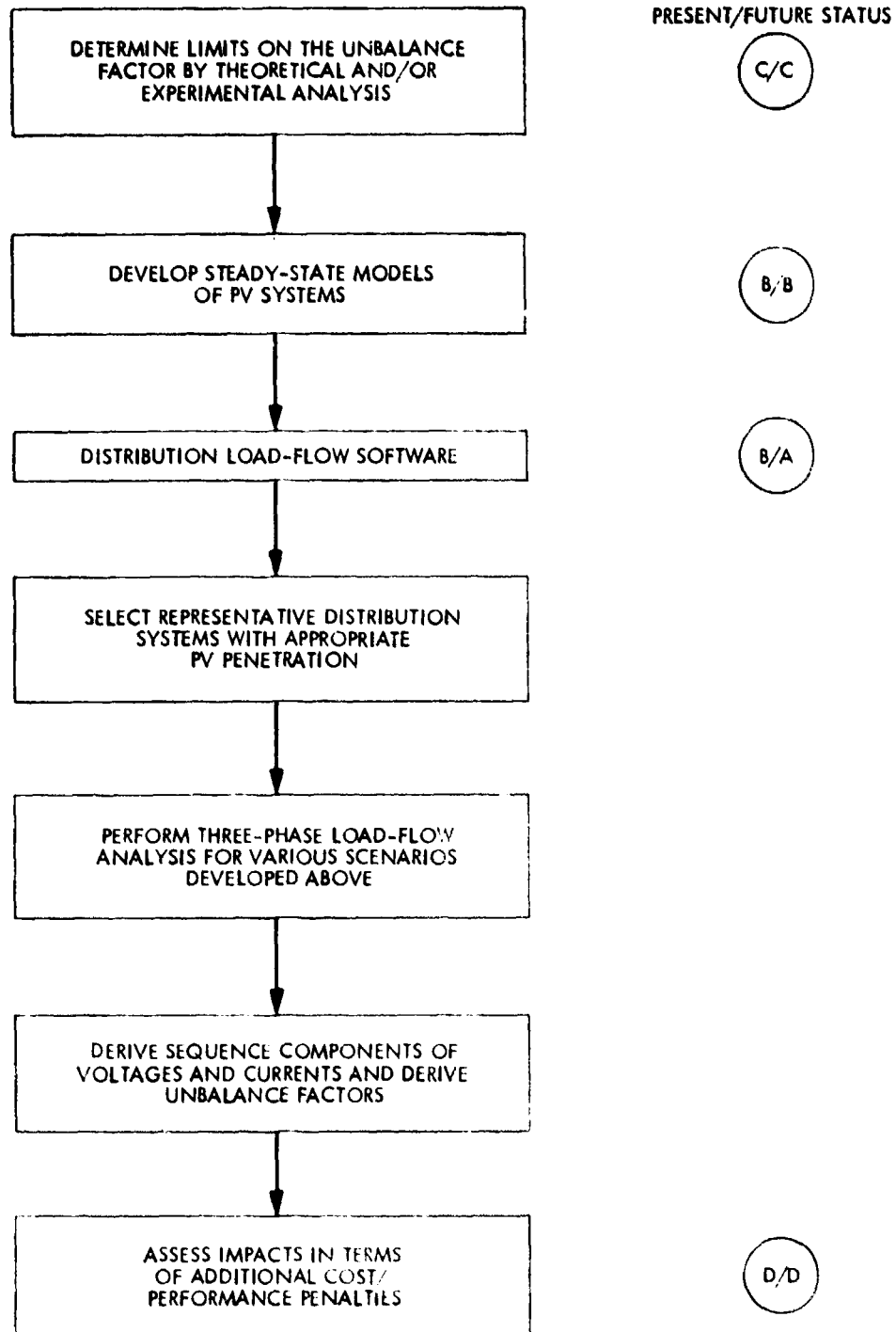


Figure 4-1. Flow-Chart Describing Recommended Plan of Action for 'System Unbalances'

SECTION V

VOLTAGE REGULATION AND REACTIVE COMPENSATION

A. INTRODUCTION

1. Definition

This definition includes proper maintenance of the voltage at the customer's terminals within an acceptable band with PV systems connected while also maintaining the flow of reactive power within limits.

2. Risk

If the utilities face problems in maintaining proper voltage at the customer's terminals and need to modify the systems, the costs of doing so may directly be passed on to the owners of the PV systems.

3. Discussion

Historically, the distribution systems were designed for one-way flow of electrical power; from the distribution substation to the load via the distribution feeder, lateral, distribution transformer, secondaries, and the customer's service line.

One of the most important operating considerations is that the voltage at the customer's terminals throughout the system should be maintained within specified limits irrespective of the magnitude of the load. The logical primary feeder design to permit maximum loading and area coverage is to assign the maximum limit (e.g., 125 V) to the customer nearest, electrically, to the source (distribution substation) and the lowest limit to the customer farthest from the substation. Figure 5-1 is a single-line diagram of a residential feeder showing feeder components and location of first and last customer. To ensure that these voltage limits are maintained, there are many methods of regulating the voltage such as load tap changing transformers (LTCs), induction and step regulators and switched capacitors (both shunt and series). All of these methods control or affect the flow of reactive power over the system.

When PV systems, however, are connected to the utility distribution system, the problem of proper voltage regulation is complicated because:

- (1) In the present day distribution systems with the flow of power in one direction only, it is much easier to ensure that the above conditions are met. It is quite simple to analyze the one-way power flow on a radial distribution system to determine the voltage levels and I^2R losses within the system. With distributed PV sources on the system, such an analysis could become quite complicated. With reference to Figure 5-1, one can no longer assign the maximum allowable voltage limit (125 V) to the customer electrically nearest to the source. The obvious solution is that the power flow analysis would have to be done by

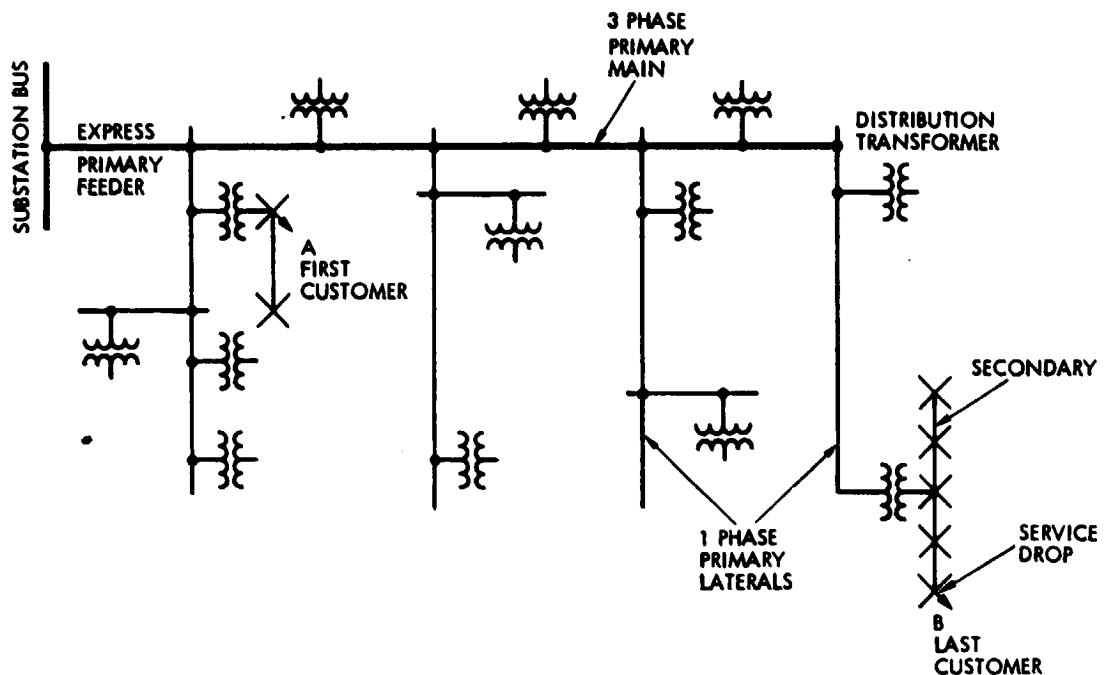


Figure 5-1. Residential Feeder Showing Feeder Components and Location of First and Last Customer

using computer codes like the ones the utilities use for the analysis of their transmission systems. Better models would need to be developed for the PV systems, voltage regulators, and the loads.

- (2) Line-commutated converters operate at lagging power factors. In other words, they draw reactive volt amperes (VARs) from the system. The utility system must be in a position to supply the additional VARs besides the VARs needed to satisfy the load requirements. Because most of the real power demand of the loads is met by the PV systems, the utility system is left with supplying large amounts of reactive power, but very little real power during high insolation levels. Thus, the ratio of VARs to real power (watts) seen by the voltage regulator at the distribution substation could be fairly high. This, in turn, could have an adverse effect on the voltage regulation on the system besides causing some secondary concerns such as higher I^2R losses, overloading of system components, etc. This problem could be alleviated by using power-factor correction capacitors. Unless switched capacitors are employed, which can be switched off during low insolation conditions, overvoltages might be experienced on the system. A self-commutated inverter can be operated at a unity power factor or possibly even a leading power factor. At this stage, however, it is not clear that a unity power factor converter is the answer because the ratio of VARs to watts at the substation would still be rather high. A possible alternative could be an inverter which could regulate its reactive power output (a variable reactive source) depending upon the system requirements.

- (3) Because the inverters operate under non-sinusoidal conditions, one cannot talk about VARs in the conventional utility sense. As yet, no standard exists for defining VARs under non-sinusoidal conditions. The IEEE guidelines (see Reference 9) do recommend a definition of power factor under non-sinusoidal conditions. However, various other authors have come up with different definitions (see References 7 and 8). The implications of these various definitions must be studied.

B. REFERENCES

1. Study of Dispersed Small Wind Systems Interconnected with a Utility Distribution System, Interim Report by Systems Control Inc. for Department of Energy Contract #DE-AC-04-76DP03533.

The study conclusion on voltage regulation is that, as the penetration of small wind systems increases their output at rated wind speed, it tends to increase the voltage profile. This raises the feeder's minimum and maximum points. Also, small, voltage-dependent wind systems lower the substation power factor while simultaneously increasing the voltage profile. Given this situation, the general conclusion about voltage regulation and line losses is that dispersed small wind systems do not present serious problems in regulation of feeder voltage and do not require additional shunt capacitor compensation.

Utilities will not have serious voltage regulation problems because:

- (1) The addition of small wind systems to a feeder will not occur suddenly; rather wind-turbine generators will be installed in small capacities throughout the utility's system. If, by chance, many are added to a particular feeder, the voltage profile will change gradually.
- (2) Utilities adjust voltage regulation equipment for normal load growth. Wind-turbine generators added to a feeder will influence this normal adjustment procedure only slightly.

Adding shunt capacitor compensation to reduce the line losses because of the presence of small wind systems may be difficult to justify for two reasons: (1) the increase in line losses is small even though the substation power factor is considerably lower than the peak load base case of no wind-turbine generators, and (2) the increase in line losses at the lowered power factor occurs only when the wind-turbine generators are producing power. As a result, the output from the wind-turbine generators and switching of capacitors would have to be coordinated. However, the extra expense for designing and installing capacitors to recover losses that occur only when the wind-turbine generators operate may not be cost-effective.

The voltage profile analysis completed so far does not include the combinations of light feeder load and higher power output for various penetrations of small wind systems. Nor does it include an examination of peak load with various penetrations of small wind systems operating near cut-in wind speed when the wind-turbine generators have very low power factors. Analyses of these additional cases may change the general conclusion.

Based purely on the conclusions of this study, if dispersed wind systems do not pose a problem for voltage regulation (up to 50%) penetration on a feeder, it is hard to imagine that PV systems would behave any differently.

2. Assessment of Distributed Photovoltaic Electric Power Systems, Final Report by JBF Scientific for EPRI Project RP 1192-1, July 1980.

(For a detailed introduction and development of the methodology, see Reference 4, Section 2-5.)

Power-flow analyses were made, aided by a load-flow computer program. The assessments were performed as follows. The load-flow program was run on a base-case T&D network without photovoltaics. Then, photovoltaics were added to the network and the load-flow was rerun. The changes in line and transformer loadings were used to assess the power flows caused by the photovoltaics. This process was repeated at several levels of PV penetration.

The program was also used to provide voltage levels at all designated buses. Bus voltages were assessed before and after the introduction of PV systems.

The initial findings of this study indicate that large backflows from distributed PV installations interfere with the operation of voltage regulators and LTC controls under light loading conditions. One possible remedy was to limit PV penetration to less than 30% for the different cases examined. It was also found that reactive power requirements from some distributed PV systems (using line-commutated inverters) tend to increase voltage drop. The recommendation is to require PV installations to have power factors in excess of 0.9.

The thrust of the study is more an economic analysis than a technical analysis. However, it does provide some interesting insight into the problems that could be expected with distributed PV systems.

3. Stratford, R.P., and Steeper, D.E., "Reactive Compensation and Harmonic Suppression for Industrial Power Systems," IEEE Transactions on Industry Application, Vol. 1A-12, No. 3, pp. 232-254, May/June 1976.

This paper discusses the problems and solutions in applying reactive compensation, either static or dynamic, to industrial power systems supplying large blocks of dc power from diode or thyristor converters. However, the resonance between power capacitors and system reactance can produce high harmonic voltages. The use of filters to minimize the interaction between these harmonic voltages and the regulating system is discussed.

The economics of reactive power compensation is discussed. Reactive volt amperes from the utility cost from \$0.15 to 0.30 per kVAR month. At these rates, it is economical to install power capacitors to furnish on-site reactive power because, as the author contends, the investment can be paid off within 9-18 months. The economics of using capacitors versus other devices (such as synchronous motors, static VAR control, regulating transformers, etc.) is also discussed.

4. Fernandes, Happ, and Wirgau, "Optimal Reactive Power Flow for Improved Systems Operations," Electrical Power and Energy Systems, Vol. 2, No. 3, July 1980.

The utilization and coordination of reactive sources and other voltage control equipment in system operations are discussed. The reactive sources studied are generators, synchronous condensers, switched static capacitors and shunt reactors, and transformers with and without load-tap changing capabilities. The benefits derived from the method presented include savings in fuel production costs, unloading of system equipment, improved system security, and improved voltages over the system.

5. Boyle, John, "VAR Control: Leading and Lagging Power Factor," paper presented to the American Public Power Association (APPA) Annual Meeting, February 1980.

The paper presents the problems associated with poor VAR control. The blackouts of New York, Jacksonville, and France are prime examples of the result.

The paper addresses the bulk level, but the author does state that fixed capacitors cannot be used in the distribution system because they might cause high voltages under lightly loaded conditions.

6. Preiss, and Warnock, "Impact of Voltage Reduction on Energy and Demand," paper presented at the IEEE PES Winter Power Meeting, New York, January 1978.

This paper reports the results of an experimental investigation of the impact of voltage reduction on the energy and demand levels of the American Electric Power System.

Many utilities are considering voltage reduction as a means of load management. With PV systems connected to the grid, it may not be as easy for the utilities to regulate voltage at their will. This should be an important consideration when designing the voltage regulation equipment for PV systems.

7. Kusters, N. L., and Moore, W. J. M., "On the Definition of Reactive Power Under Non-Sinusoidal Conditions," #F79621-4, presented at the IEEE-PES Summer Meeting, Vancouver, BC, July 15-20, 1979.

A new method of defining reactive power under non-sinusoidal conditions is proposed. This consists of subdividing the current into three components: (1) those with the same waveform as the current in a resistance, (2) those with the same waveform and phase as that of a current in an inductor or capacitor and, (3) into a residual component. Essentially, taking the voltage as the reference, this divides the current into:

- (1) An active current component which has the same waveform and phase as the voltage (and thus, the same waveform and phase as the current in a resistor with the same voltage across it).
- (2) An inductive reactive current component which has the same waveform and phase as the current in an inductor with the same voltage across it, or a capacitive reactive current component which has the same waveform and phase as the current in a capacitor with the same voltage across it.
- (3) A residual reactive current component, either inductive or capacitive, is that which remains of the total current after the active and the respective inductive or capacitive reactive current components have been extracted.

An instrument for subdividing and measuring each current component and its corresponding power is described. The method permits the power system operator to determine if the possibility exists to improve the power factor by a shunt capacitance or an inductance and to easily identify the proper value required to realize the maximum benefit.

8. Shepperd, W., et al, "Power Factor Correction in Non-Sinusoidal Systems by the Use of a Capacitance," Applied Physics, Vol. 6, p. 1850, 1973.

The apparent voltamperes into a non-sinusoidal circuit can be considered as the resultant of three hypothetical components known as the active voltamperes S_R , the true reactive voltamperes S_X , and the apparent distortion voltamperes S . In systems with non-sinusoidal voltage, the active voltamperes S_R differs from the average power P , and the true reactive voltamperes S_X differs from the quantity, $Q = \sum_{n=1}^n E_n I_n \sin \phi_n$, frequently quoted in the literature.

The reactive voltamperes of an inductive load can only be completely compensated by capacitance to give a unity power factor when the load impedance is linear and the voltage is sinusoidal. If the load impedance is nonlinear, the load voltage is non-sinusoidal or both. Some improvement of power factor may be realizable by capacitance compensation, but the highest power factor achievable is less than unity.

Formulas are developed to give the maximum power factor and the minimum reactive voltamperes achievable by capacitance compensation. The optimum value of capacitance to give maximum power factor operation is defined for the cases of non-sinusoidal voltage supplying a nonlinear load, non-sinusoidal voltage supplying a linear load, and sinusoidal voltage supplying a nonlinear load.

9. IEEE Guide for Harmonic Control and Reactive Compensation of Static Power Converters, IEEE Project #519, July 1979.

This guideline defines the converter power factor as two components: (1) displacement and, (2) distortion. The effects of these two components are combined into the total power factor.

The displacement component is the ratio of the active power of the fundamental wave in watts to the apparent power of the fundamental wave in voltamperes. This is the power factor in watt-hour and VAR-hour meters used in utility metering.

The distortion power factor is the ratio of the fundamental component of ac line current to the total line current.

The guideline further discusses ways of reducing reactive power requirements of static converters by limiting phase control, lowering reactance of converter transformers and sequential converter control, etc. It also discusses methods of reactive compensation such as capacitors and static VAR control. Methods of reducing possibility of resonances are also discussed.

10. Impact of Dispersed Solar and Wind Systems on Electric Distribution Planning and Operations, Final Report, SCI for Oak Ridge National Lab, Report # ORNL-SUB-7662-1, February 1981.

This study examined the effects of dispersed solar photovoltaics and wind systems on distribution system operation. The findings regarding impacts on voltage regulation are summarized below.

When dispersed sources produce power, their output changes the feeder's voltage profile. Voltage source generators (such as forced-commutated inverter systems and synchronous generators) produce their own reactive power and tend to increase the voltage at the point of connection by reducing the load. Voltage-dependent sources such as line-commutated inverter systems and induction generators draw reactive power to produce real power output. They also tend to increase the voltage, but to a lesser extent than voltage-source generators.

In general, as the penetration of dispersed sources increases along a feeder, the minimum and maximum voltage points on the feeder increase. This happens irrespective of the generator type, i.e., voltage sources or voltage dependent. For low penetrations, 5 and 20%, the increased voltage profile does not exceed the utility's maximum voltage criteria. However, higher penetrations cause the maximum voltage criteria to be exceeded.

In all cases examined, the dispersed generators narrowed the range between the feeder's minimum and maximum voltage points. This is caused by the high resistance characteristics of the distribution feeder. As load is reduced by the output of the dispersed generators, the real current is reduced, significantly increasing the voltage. The effect is seen clearly when comparing the synchronous generator and the induction generator cases. Although the induction generator increases the reactive current, there is very little difference between the two voltage profiles.

The assertion, made in the study, that distribution feeders exhibit high resistance characteristics is not totally correct. This may be true for underground feeders, but is certainly not valid for overhead distribution feeders where line reactance predominates over line resistance.

C. GUIDELINES/STANDARDS

1. Voltage Ratings for Electric Power System and Equipment (60 HZ), ANSI C84.1-1970, including Supplement C84.1a-1973.

This guideline gives standard voltage ratings used in electric power system and equipment applications.

2. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

The guidelines regarding reactive power generation and voltage regulation are:

- (1) The operation of the production facility shall not produce excessive reactive power during offpeak conditions nor consume excessive reactive power during onpeak conditions.
- (2) The owner shall provide necessary voltage regulation equipment to prevent the production facility from causing excessive voltage variation on the connecting electric system. The voltage variation caused by the production facility must be within ranges capable of being handled by the voltage regulation facilities used by the connecting electric system.
- (3) The voltage surges caused by the operation, synchronization, or isolation of the production facility shall be within the standards of frequency of occurrence and magnitude established by the connecting electric system to prevent undue voltage flicker on the connecting electric system.

The ranges of reactive power consumption/generation and the voltage variations are not specified at all.

3. Interconnection Facility and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

(For specific details, see Reference 6 under Guidelines in Section II-G)

Regarding reactive power generation/consumption by the QF, the study presents the following alternative solutions for determining a power factor standard. Each alternative includes the assumptions upon which the solution is based.

- (1) Ignore the situation. This alternative assumes that the number and size of QFs will have a negligible impact on the utility's distribution system.
- (2) Require that the net power factor of the QF generation and load meet present utility power factor rules applicable to other customers. For example, a typical utility requirement is that the customer's power factor equal or exceed 0.85 at all times. This alternative treats the QF as a load. The effect of this alternative is that the QF customer will be required to provide some, if not all, of the reactive requirements.
- (3) Require that the net power factor of the QF generation and load be unity (1.0). This alternative essentially treats the QF as an

interconnected utility with a power factor obligation similar to that included in interconnection agreements between utilities. In this case, all the QF's reactive requirements would have to be self-generated.

- (4) Require that the power factor of the QF generator (alone) meets or exceeds some specific standard such as 0.85. This alternative treats the QF generation independent of the load connected to the QF. The minimum power factor chosen to apply to QF generation will depend upon the expected effect of the reactive requirements of each QF generator and the combined effect of all QFs on both utility system operation and cost. In conjunction with this particular alternative, the utility may also choose to apply its customary power factor standard to the load of the QF system.

Relative to all preceding alternative solutions, the utility will have to make some decisions regarding metering to monitor QF power factors/VARs. These decisions involve the following alternative metering factors:

- (a) Power factor vs. VARs.
- (b) VARs vs. VARh.
- (c) Maximum vs. time-of-day vs. average.
- (d) QF generation VARs vs. net VARs of the QF generation and load.
- (e) Sampling vs. continuous monitoring.

The characteristics of individual utilities are too varied to recommend a particular alternative that would be appropriate for all utilities. Therefore, each utility should develop its own power factor standard(s) applicable to QFs. In the process of doing so, each utility should evaluate its: (1) system needs, (2) rates and other provisions developed for application to the QF, and (3) assumptions on the number and type of QFs expected.

Regarding voltage regulation it is recommended that each QF applying for service be required to provide a reasonable estimate of its load without generation, and the capacity, type, and operating characteristics of the QF.

If, under any circumstances unacceptable voltage regulation, as defined by the utility, is expected to occur or does occur specifically because of the QF, the QF should be disconnected, or not allowed to be connected, until the unacceptable voltage is corrected.

Utility rules and regulations should be changed or expanded, as necessary, to require voltage regulation by QFs within limits acceptable to the utility.

4. San Diego Gas & Electric Company, Protection and Operation Guidelines for Cogenerators and Small Power Producers, Preliminary Draft submitted to California PUC.

The excerpts from this draft pertaining to voltage regulation are:

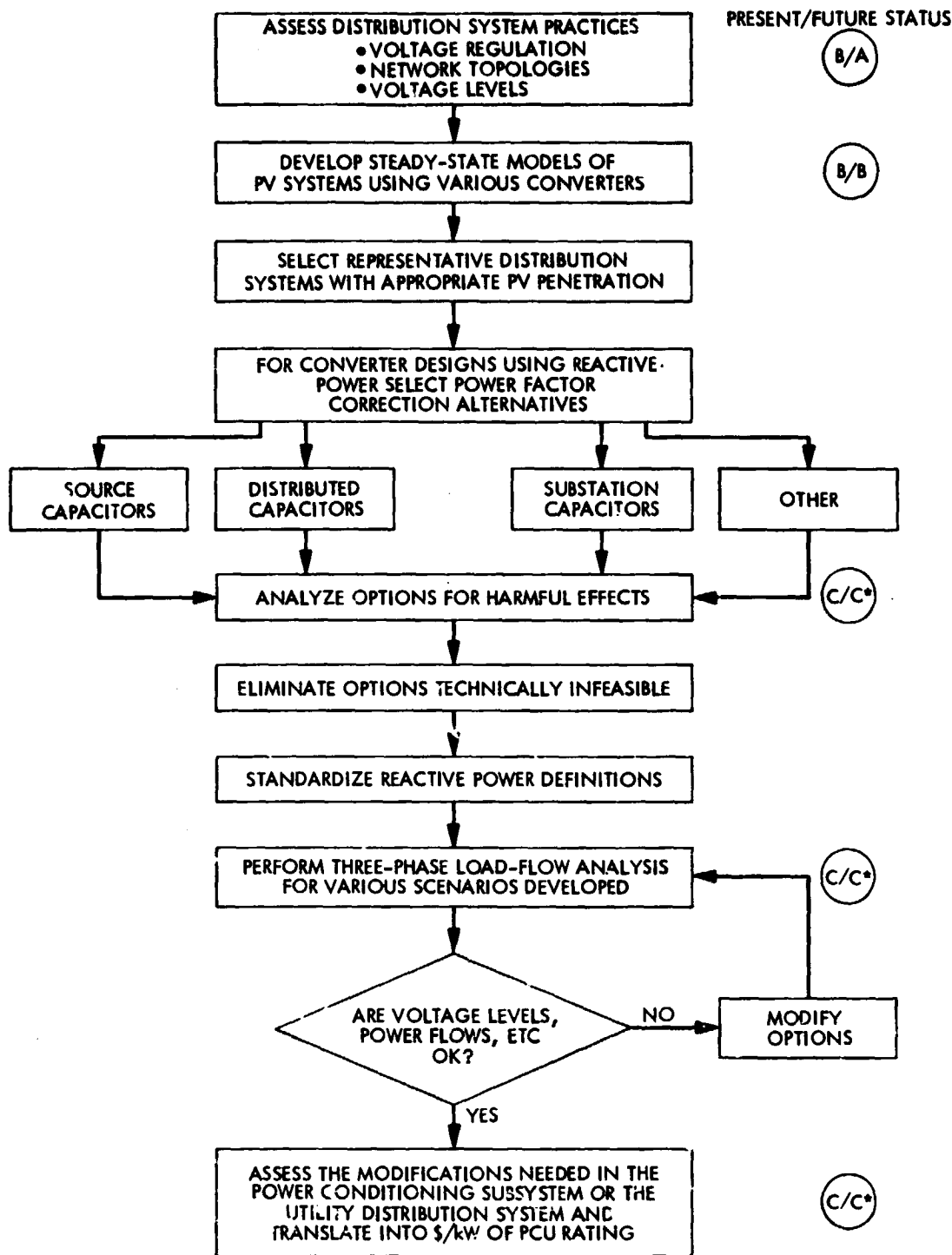
- (1) The customer should maintain his power factor within a reasonable range. For small generators, power factor correction is not desirable.
- (2) Voltage regulation equipment will be required on the customer's generator to maintain service voltage within normal utility limits. If high or low voltage complaints or flicker complaints result from operation of the customer's generation, such generating equipment shall be disconnected until the problem is resolved.

D. CONCLUSIONS

- (1) No standard definition exists for the definition of power factor (or reactive power) under non-sinusoidal conditions.
- (2) For converters operating at lagging power factors, it may be more economical to correct the power factor using capacitors than having the utility supply VARs and charge for it. However, using capacitors on the system can cause undesirable interaction with harmonics (system resonances).
- (3) Initial study of dispersed generation has shown that the impact on voltage regulation is quite nominal unless the penetration gets quite high (around 50%). However, reverse power flows and changes in power factor can cause problems with proper operation of voltage regulators.
- (4) Utility guidelines studied did not specify any band within which the dispersed generator (PV system, for example) had to regulate its voltage.

E. RECOMMENDATIONS

Figure 5-2 shows, in flow chart form, the recommended plan of action for the resolution of the various issues. Some of the boxes are the same as ones shown in Figure 4-1 because each deals with basic steady state models and software. The status of the major problem areas is shown in Table 5-1.



*THE STATUS OF THESE ISSUES MIGHT BE UPGRADED IN THE FUTURE, REFLECTING TASKS OUTLINED IN A NEW TECHNOLOGY INTEGRATION PROGRAM PLAN BEING DEVELOPED BY DOE/EES AND NOT AVAILABLE AT THE TIME OF PUBLICATION.

Figure 5-2. Flow Chart Showing Recommended Plan of Action to Resolve the Issue of Voltage Regulation and Reactive Compensation

Table 5-1. Voltage Regulation: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Assess present distribution practices	B	A	Section IX (2)
Develop steady-state models of converters	B	B	-
Study system resonances	C	C	-
Develop three-phase distribution load-flow software	B	A	-
Assess system modifications to maintain required voltage and power-flows	C	C	-

A	The issue is completely resolved or can be resolved when based on available knowledge.
B	Much is known or documented, but the issue is not totally resolved.
C	Very little is known or documented.
D	Nothing is known or documented.

SECTION VI

HARMONICS

A. INTRODUCTION

1. Definition

The definition of harmonics is the maximum amount of voltage and/or current harmonics produced by a PV system (at its terminals) when connected to a utility power system.

2. Risk

Harmonics (both current and voltage) have a lot of undesirable effects associated with them. If a PV system produces excessive harmonics and thereby causes problems with the utility power system, the utility may ask the PV system to be shut down until the problem is corrected.

3. Discussion

Without the integration of PV sources, there are many other sources of harmonics on existing distribution systems. In general, devices with nonlinear operating characteristics produce harmonics. Some examples are transformer magnetizing currents, arc furnaces and welders, thyristor controlled devices, rectifiers, etc.

The introduction of PV sources into the grid will magnify the level of harmonics on the system due to the harmonics produced in the dc to ac conversion process. Of the various types of conversion alternatives available, two approaches commonly applied today and discussed in Section II-C.3. produce different types of harmonics. The Current Fed Line-Commutated Inverter (CFLC) produces current harmonics while the Voltage Fed Force-Commutated Inverter (VFFC) produces voltage harmonics. In both cases, the level of harmonics imposed on the system is a function of system impedance at the point of interconnection as well as the characteristics of the inverter itself.

The order of harmonics produced by either type of converter is a function of the switching design and can generally be classified into the following categories:

- (1) Characteristic harmonics: These harmonics are produced if ideal switchings occur within the inverter.
- (2) Uncharacteristic harmonics: These harmonics are of the order other than (1) above that are caused from unbalanced line voltages, noise in the electronic circuits controlling the switching and interactions of characteristic harmonics and fundamental currents in non-linear portions of the system.

- (3) High frequency harmonics: These harmonics in the tens of kHz range are produced due to commutation notches in the supply voltage.

The undesirable effects of harmonics are summarized below. No effort is made to isolate effects from voltage or current harmonics because they are essentially duals of each other, i.e., one produces the other.

- (1) Overheating of capacitor banks due to lower impedance to higher order harmonics.
- (2) Overheating in rotating machines and transformers. Harmonics do influence motor torque also, but this effect is not thought to be significant.
- (3) Interference with utility ripple and carrier current systems.
- (4) Interference with voice communication (telephone interference).
- (5) Overvoltages due to resonance.
- (6) Instability in converter controls.
- (7) Malfunctioning of protective relays.
- (8) Errors in metering real and reactive energy.
- (9) Malfunctioning of connected loads, such as computers.

Development of a viable standard for harmonic limits of individual power conditioning units could be a very complex procedure. It would involve determining the maximum allowable harmonic limits at any point on the system and translation of this number into an allowable harmonic injection (voltage or current) at the terminals of the converter. This limit would depend on the characteristics of the distribution system, background harmonic level from other sources on the system and most important to the penetration level (both local and system-wide) of PV sources. It would also involve extensive system simulations and field measurements.

B. REFERENCES

1. Kimbark, E. W., Direct Current Transmission, Vol. I, Wiley Interscience, 1971.

Chapter 8 of this book discusses the generation of voltage and current harmonics by HVDC converters. Fourier analysis of the current and voltage waveforms under various operating conditions is performed. The origin of uncharacteristic harmonics and the undesirable effects of harmonics themselves

are discussed. There is emphasis on telephone interference, discussing the various weighting systems (such as the Bell Telephone System, Edison Electric Institute, and the International Commission of Consultative Commission on Telegraph and Telephone Systems). Reduction of harmonics including criteria for selecting harmonic filters is addressed in detail. The effect of network impedance on filtering is also adequately covered.

This book is an excellent treatment of harmonics. It condenses much useful information in one chapter.

2. Campen, G. L., Preliminary Report on the Results of the ORNL Sponsored Measurement Program at the J. F. Long Photovoltaic Home in Phoenix, Arizona, by Oak Ridge National Lab, December 19, 1980.¹

This is a preliminary report on the various measurements carried out at the J. F. Long PV home in Phoenix, Arizona. The measurements were made in a four-day period in October 1980. The quantities measured were current and voltage harmonics with the PV system on and off, real and reactive power flows with the PV system, on and the impedance characteristics of the system. Although many measurements were made, preliminary analysis showed some errors between measured and calculated values. These could be attributed to instrumentation, poor frequency response of transducers, etc. It will take some more time before the extensive volume of data gathered can be properly analyzed and any firm conclusions drawn.

This represents a good first step towards resolving the issue of allowable harmonic limits for PV systems for DOE.

3. Guidelines for Voltage Harmonics Prediction in Distribution Feeders, prepared by Worcester Polytechnic Institute/New England Electric System Group under Contract #223221, June 1978.

The goal of this guideline is to enable the distribution engineer to predict harmonic voltages as a function of rectifier or inverter type and power rating.

The tolerable level of harmonics depends on the type of device exposed to harmonics. Figure 6-1 presents recommended levels of individual harmonics for six basic types of loads. These guidelines must be interpreted so that,

¹At the time of this printing, the draft final report for this task has just been received. Thus, the findings from this study could not be included in this report.

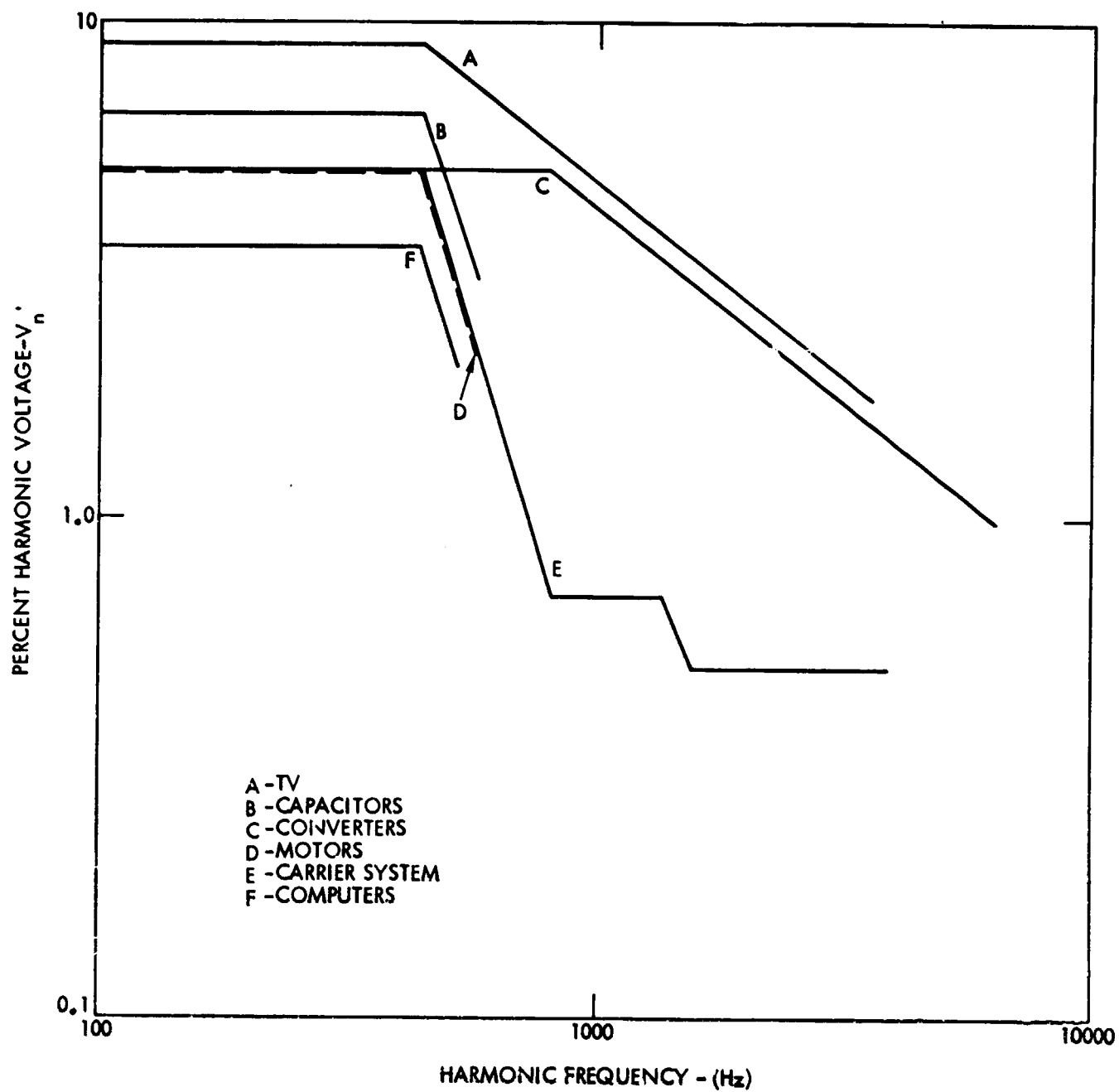


Figure 6-1. Acceptable Levels for Voltage Harmonics

to ensure the proper performance of an electric device connected to a certain bus, a voltage harmonic shall not exceed the limit indicated in the figure. Table 6-1 gives the maximum recommended voltage distortion factors (DF).

The guidelines present three methods of determining harmonics in any given power system. They are: (1) exact method, (2) simplified method, and (3) a method using no computations. In the exact method, the impedance of the entire network is modeled for each frequency and the voltage harmonics are computed for each value of the harmonic frequency at each bus. This seems to be quite similar to the computer program developed by the McGraw-Edison Company for EPRI (see Reference 4 in this Section). In the simplified method, the input data are kept to a minimum. This method can be used if there is a customer transformer between the converter bus and the utility bus. An additional condition is that the transformer impedance must be at least twice the system short-circuit impedance at the converter bus. In the no-computation method, no further calculations are necessary if the converter load is small with respect to loads other than the converter load connected at the studied bus. The local load damps out the current harmonics effects and the expected voltage harmonics are below all the accepted levels for all types of equipment. The necessary criteria for such a condition are clearly illustrated. Some numerical examples are worked out to illustrate how the various methods work.

These methods are more suited to situations when there are isolated large size converters connected to the system. The applicability of such an analysis for distributed PV case must be verified.

4. Study of Distribution Systems Surge and Harmonic Characteristics, Final Report EL-1627, prepared by the McGraw-Edison Company for EPRI, November 1980.

Table 6-1. Maximum Acceptable Voltage Distortion Factor

Device	Voltage Distortion Factor (DF), %
TV	Not Given
Capacitors	9.19
Solid State Devices (inverters and converters)	10.00
Motors	7.07
Communication Carrier Systems	Not Given
Computers	5.0

The objectives of this project were:

- (1) To determine the effects of harmonics and noise on distribution systems and equipment.
- (2) To evaluate equipment and methods for measuring harmonics and noise.
- (3) To develop analytic techniques for studying distribution network response to harmonics.
- (4) To evaluate methods to reduce harmonics.
- (5) To investigate requirements for surge protection of converters.

Section 2 of this report discusses the nature of the various harmonic producing sources on the system such as transformers, rotating machines, and equipment, converters, etc. It also discusses the harmful effects of harmonics on various equipment. Most of the findings are based on a literature search rather than actual analysis or experimentation on the various equipment. Section 3 discusses the high frequency noise characteristics of distribution systems. The sources of high-frequency noise on the system are described; the instrumentation used to measure the noise is also discussed. Spectrum analyses displays of background noise on two utility distribution systems are presented. Section 4 discusses the origin of various types of voltage transients on the system. It also discusses the ill-effects of these surges on converters and ways to mitigate them. Section 5 describes the instrumentation and test methodology employed to measure current and voltage harmonics and voltage surges on two utility distribution systems. Section 6 briefly describes the analytical techniques for simulating the impact of harmonics on any given distribution system. The results of analytical studies are compared with actual field measurements. Section 7 discusses the harmonic reduction and surge suppression techniques. Section 8 presents the overall conclusions.

Appendix A presents an abstract of the many references available on the subject. Appendix B provides the description of the computer program Distribution Feeder Harmonic Analysis (DFHA).

This study has identified various sources of harmonics on distribution systems and their effect on the various equipment. It also demonstrated that satisfactory instrumentation for measuring harmonic currents and voltages is available. The field tests demonstrated the validity of using analytical models of ac/dc power converters to predict the magnitudes of harmonics generated on the system. Computer analyses predicted frequencies causing resonance or current/voltage magnification to an accuracy within 5%. Magnitude predictions varied with the location. Near the harmonic source, the results were no less than 50% inaccurate (on the order of 20% inaccurate for harmonics below 19th). Far from the harmonic source, inaccuracies of several hundred percent were encountered.

This study gives a better understanding of the complex interaction of harmonics with distribution systems and their impacts on various equipment. Although the study concentrated on Megawatt (MW) size converters, some of the

results obtained and the methodology developed for analysis would be very helpful to the PV Program. In its entirety, this report is one of the best references on this subject.

5. Stratford, R. P., "Harmonic Pollution on Power Systems - A Change in Philosophy," IEEE Transactions on Industry Applications, Vol. IA-16, No. 5, September/October 1980.

Combinations of static power inverters and power capacitors can create problems on the system. There are commonsense rules to use to determine if there is a problem. The following definitions are used:

$$f_p = \left(\frac{X_c}{X_{sc}} \right)^{1/2}$$

where

f_p = per-unit parallel resonant frequency

X_c = capacitor bank reactance (per-unit or ohms)

X_{sc} = system reactance (per-unit or ohms)

$SCR = \frac{\text{short-circuit MVA}}{\text{converter MW}}$

If SCR is above 20 and f_p is below 8.5, the probability of problems is low. If SCR is below 20 and f_p is near one of the converter characteristic harmonics, there is a high probability of producing excessive harmonic voltage and currents.

The typical industrial systems have parallel resonances near the band 300-420 Hz when correcting the power factor to 0.9-0.95. Thus, the fifth and seventh harmonic currents are of the greatest concern. In examples given in the paper, it is shown that the rms capacitor currents can go as high as 1.42 per unit under certain resonant conditions. The recommendation is to use tuned filters for fifth and seventh harmonic frequencies.

Interesting highlight is the actual oscilloscope patterns of currents and voltage on an industrial system with converters.

6. Stratford, R. P., and Steeper, D. E., "Reactive Compensation and Harmonic Suppressions for Industrial Power Systems," IEEE Transactions on Industry Applications, Vol. IA-12, pp. 232-54, May/June 1976.

The paper discusses the undesirable effects of harmonics and shows an oscillogram of converter instability due to harmonics. The ways to eliminate harmonics are discussed with emphasis on shunt filter design. Current practices for allowable harmonics for various HVDC installations are presented. Some of the experiences with industrial users is also discussed when the requirements on total voltage harmonic distortions are less than 3%. The paper contains oscillograms of currents and voltages with and without shunt filters.

This is a very interesting paper. It is probably one of the best references on harmonics.

7. Chandra, N., et al, "Prediction of Harmonic Voltages in Distribution Systems," paper #80 SM 667-6, presented at IEEE-PES Summer Meeting, Minneapolis, Minnesota, July 13-18, 1980.

This paper develops workable models for specific devices that are known to inject harmonics into power distribution systems (such as ac/dc converters). This includes both the line-commutated and self-commutated types. These models are combined with the models of the various elements of the power system, such as transmission lines, transformers, etc., and the resulting network is solved to yield harmonic voltages. An example is presented applying the techniques to analyze a real-life installation.

The analysis technique presented is quite interesting. It could possibly work with many distributed sources on the system.

8. Investigation of Maximum Tolerable Level of Voltage and Current Harmonics, ongoing DOE/EES Contract with University of Colorado, Contract #AC02-80RA-50150.

The effort so far has concentrated on a literature search, trying to identify the various standards or guidelines existing on harmonics worldwide. Also, experiments were performed to determine the effects of harmonic and subharmonic voltages on home appliances, such as TVs and single phase motors. Experimentation is still going on, and preliminary conclusions are as follows:

- (1) Smaller induction motors (~1/3 hp) with relatively large inductances are less sensitive to temperature rise because of harmonics and subharmonics than large motors (~1 hp) with relatively small inductances.
- (2) In linear (unsaturated) induction motors, the additional losses from harmonics and subharmonics depend only on the amplitude of

the harmonics or subharmonics. In the case of non-linear (saturated) induction motors, the amplitude and the phase shift, with respect to the fundamental, are important.

- (3) The proper functioning of television sets can be impaired by the presence of harmonics or subharmonics in two ways:
 - (a) The television picture becomes enlarged and reduced periodically if subharmonics of lower order in the terminal voltage exceed certain voltage levels.
 - (b) The dc power supply network (transformers, capacitors) may become overheated if harmonics or subharmonics are above a certain voltage level.

This is quite an important study. The results obtained should have ramifications on the issue of maximum tolerable level of harmonics. However, due to the limited nature of this study, it will not provide all the answers to the problem.

- 9. Shepard, J. D., "Switching Supplies - The FCC, VDE, and You," Electronic Products Magazine, p. 51, March 1980.

This reference compares the EMI standards imposed by the Federal Communication Commission (FCC) and the European agency with the strictest EMI requirement, West German Verband Deutschen Electrotechniken (VDE).

The FCC has established two classes of devices: (1) Class A, intended for use in commercial, business, and industrial environments, and, (2) Class B, intended for use by the general public in a home or a residential environment. Although FCC will require certification for some Class B devices, certification will not be required for any Class A device.

The FCC specifications for conducted emissions currently cover the 450-kHz to 30-MHz spectrum. This excludes the low-frequency portion between 10 and 450 kHz in which most fundamental switches and low order harmonics occur. Conducted limits for this frequency range are still under consideration by the FCC.

The comparison of the FCC and VDE standards is shown in Figure 6-2.

- 10. Jordan, H. E., and Klingshirn, E. A., "Polyphase Induction Motor Performance and Losses on Non-sinusoidal Voltage Sources," IEEE Transactions on PAS, Vol. PAS-87, p. 624, March 1968.

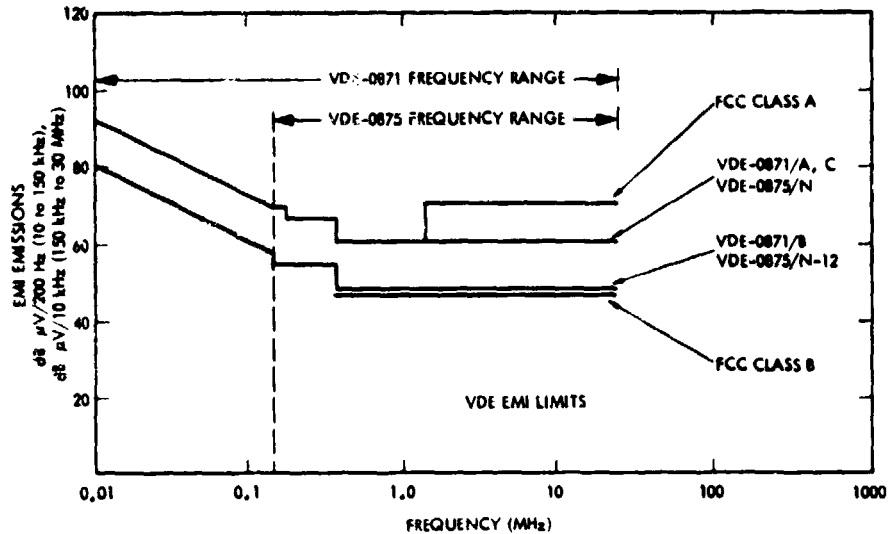


Figure 6-2. Comparison of FCC & VDE EMI Limits

Induction motors excited with static frequency converters almost invariably are subjected to non-sinusoidal voltage waveforms. The presence of time harmonics in the applied voltage results in currents at the harmonic frequencies. These currents result in additional and, sometimes, rather large losses. A method for calculating these harmonic currents and losses is presented; experimental data are included to substantiate it. The losses are separated into various components. The largest loss is usually in the rotor bars as a result of deep bar effect. Harmonic losses are nearly independent of motor load. The fundamental magnetizing current increases over that which would be present for the same rms fundamental voltage. These observations are explained on a theoretical basis and the encouraging correlation between test and calculated data confirms that the important elements which differ between motor performance on sinusoidal and non-sinusoidal waveforms have been identified and accounted for.

In an example presented, it is shown that for a six-step voltage wave (30% total harmonic distortion), the increase in motor losses amounted to about 20%.

11. Doggett, L. A., and Queer, E. R., "Induction Motor Operation with Non-Sinusoidal Impressed Voltages," Transactions of the AIEE, pp. 1217-1220, October 1929.

This paper presents results from analytical treatment and actual tests to determine the impact of harmonics on an induction motor. The conclusions are that with harmonics of 10% or less, the harmonics produce an insignificant effect for all types of induction motors and for all conditions of operation except the no-load condition. In this case, a significant but not serious increase of I^2X (reactive consumption) occurs. Also, lightly loaded motors may smooth out the impressed electromotive force wave.

12. Jain, G. C., "The Effect of Voltage Waveshape on the Performance of a Three-Phase Induction Motor," AIEE Transactions, pp. 561-566, June 1964.

A Fourier analysis of the output voltage waveshapes of low-frequency sources shows that, depending upon the order, a harmonic component of the voltage may contribute either positive, negative, or no torque. Using the concept of rotor-time-constant expressions for total developed torque, stator current and copper losses are derived for a voltage wave composed of harmonics of various magnitudes and orders. The stator current is affected if the motor neutral is connected to the supply neutral.

The analysis performed shows that, with a voltage wave rich in harmonics, the machine operates as if the applied sinusoidal voltage were decreased. The effect of harmonics of orders $3n + 1$ ($n \neq 0$) and $3n + 2$ is practically negligible. The effect of harmonics order $3n + 3$ is noticeable in the stator current if the rotor leakage reactance is small and the motor neutral is connected to the supply neutral.

13. Electrical Noise and Harmonics on Power Systems-
Measurements, ongoing project EPRI RP 2017.

A new start by EPRI directed at field measurements of noise and harmonics on a total of 100 feeders in distribution systems of 10 utilities. Anticipated completion is March 1983. The results should provide valuable data on present levels of harmonics and noise (without DSGs).

14. An RF Model of the Distribution System, Work
performed by General Electric for DOE,
JPL managed, Contract # EC-77-C-01-2100.

A follow-on study to the original RF Model Study in which harmonics and noise will be included in the model. The results should be of value in modeling distribution systems and the propagation of harmonics thereon.

15. Investigations of a Family of Power Conditioners
Integrated into the Utility Grid, DOE Contract
DE-AC02-79ET 29359 with Westinghouse Electric
Corporation, Draft Final Report, January 1981.

In this study, the recommendations of allowable harmonics injection are based on existing European standards. The study recommends a 5% total harmonic current distortion limit with a superposed limit on individual components of $15/N$ amps where N is the harmonic order. These limits apply to an individual converter.

However, according to the authors, these specifications are still considered tentative and subject to modification, either tightening up of or relaxing from further studies or field evidence, on this particular issue.

C. GUIDELINES/STANDARDS

1. "Guidelines for Allowable Harmonic Voltages for HVDC Applications" (from Reference 1 above).

The proposed limits of harmonic voltage/current for various HVDC projects are tabulated in Table 6-2.

2. European Guidelines/Specifications on Harmonics²

Many European countries have existing guidelines and/or specifications regarding maximum tolerance level of voltage and current harmonics. However, it is confusing to compare the various guidelines because most of them use different parameters to specify the limits on harmonics. To be able to draw a comparison, the various Parameters encountered in the various guidelines are defined:

I_n = Injected line current (A) of the order n

V_n = Voltage harmonic (line-to-neutral) of order n (V) (see footnote 3 below)

V'_n = Percentage voltage harmonic of order n based on fundamental

Z_{sc} = Short circuit impedance of the system at the point of connection

²Based on an actual study of some of the guidelines and an excellent summary prepared by A. S. Emanuel for IEEE Working Group on Harmonics.

³There seems to be some confusion about this definition. Some guidelines specify a limit on the voltage injected due to a harmonic source (generally $\approx n I_n Z_{sc}$ unless defined otherwise). Others specify a limit on the maximum tolerable voltage on the system which could be due to many harmonic producing sources on the system. Whenever such a distinction is made, it will be clearly brought out.

Table 6-2. Limits on Harmonic Voltage/Current for HVDC Systems

Project or Author	Limits on Maximum Deviation From Sine Wave ^a (H ₆), %	Limits on Every Characteristic Harmonic Voltage, %
Ainsworth ^b	3-5	--
Kingsnorth ^c	2.5 (for characteristic harmonics only)	1
Sardinia ^c	4	--
New Zealand ^c	--	0.7

^aH₆ is defined as =
$$\frac{\sum_{h=2}^{\infty} I_h}{I_1}$$

where

I_h = harmonic current of order h
 I_1 = the fundamental current

^bAuthor.

^cVarious HVDC Projects.

DF = Percentage voltage distortion =
$$\sqrt{\sum_{n=2}^{\infty} (V'_n)^2}$$

S_{sc} = Short-circuit capacity (MVA) at the point of injection

Although some of these guidelines are quite extensive, only the information pertinent to the present study is presented here.

a. Switzerland. The admissible levels of voltage harmonics at the connection bus are given in Table 6-3. According to the definition above, it seems that these limits are from one specific source. Using the numbers given, the maximum allowable voltage distortion from a single source is (DF) = 1.9%.

b. France. Again, the maximum harmonic voltages from a source are specified as:

$$\begin{aligned} V'_n &< 1\%, n \text{ odd} \\ V'_n &< 0.6\%, n \text{ even} \\ DF &< 1.6\% \end{aligned}$$

Table 6-3. Admissible Levels of Voltage Harmonics at Connection Bus (Switzerland)

Harmonics	Harmonic Order	Maximum Admissible Value of V_n , %
Odd	3	0.85
	5	0.65
	7	0.60
	9	0.40
	11	0.40
	13	0.30
	15	0.25
	↓	↓
	39	0.25
Even	2	0.2
	↓	↓
	40	0.2

where,

$$V_n = nZ_{sc}I_n \text{ for low voltage systems}$$

$$= 3nZ_{sc}I_n \text{ for medium voltage systems}$$

and

$$V_n' = \left(\frac{V_n}{V_1} \right) 100$$

where,

V_1 is the fundamental voltage.

c. Netherlands. The admissible levels of voltage harmonics from a single source are specified in Table 6-4.

Table 6-4. Admissible Levels of Voltage Harmonics From a Single Source (Netherlands)

Harmonic Order	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Allowable Voltage $V_n(\%)$	0.2	0.85	0.2	0.65	0.2	0.6	0.2	0.4	0.2	0.4	0.2	0.3	0.2	0.25	0.2	0.25

This recommendation is an exact duplicate of the Swiss recommendation. however, it is limited to the first 17 harmonic orders.

If the system voltage level and the short-circuit capacity at the point of connection are known, the injected current I_n for any individual harmonic frequency can be determined as:

$$I_n = \frac{V_n}{100} \frac{S_{sc}}{\sqrt{3}V} \frac{1}{n}$$

where V is the system line-to-line voltage. Thus, for a 380-V line-to-line three-phase system and a short-circuit capacity of 4 MVA, the allowable third harmonic injected current is 17.3 A.

d. Germany. The German recommendations are somewhat different than the previous ones. They specify limits on the total system voltage and not the contributions from individual sources.

The general goal is that the 5th and the 7th harmonic voltages in the system shall not exceed 5% and the 11th and the 13th shall not exceed 3%.

There are also limits specified for the maximum allowable ratings of the various types of rectifiers (6 pulse, 12 pulse controlled and uncontrolled, etc.) based on the system short-circuit capacity at the point of connection.

e. Sweden. The voltage harmonics from a source at the point of connection are specified in Table 6-5. These recommendations are more relaxed than the French and Swiss recommendations.

Also, the maximum size of the harmonic source is specified as a function of the short-circuit level at the point of connection.

f. United Kingdom (UK). There is an unconditional acceptance of the harmonic producing source if the rating (in kVA) of the source is less than the limits specified in Table 6-6.

Table 6-5. Voltage Harmonics From a Source at Connection Point (Sweden)

Maximum Network Voltage	Individual Harmonic Voltages $V_n, \%$	Total Distortion Factor (DF), %
430/250 V	3.0	4
3.3-24 kV	2.5	3
36-72 kV	1.5	2
84 kV and above	0.7	1

Table 6-6. Limits on Rating of Harmonic Producing Sources (UK)

Supply Voltage, kV	Three-Phase Converters, kVA			Three-Phase AC Regulators, kVA	
	3 Pulse	6 Pulse	12 Pulse	6 Thyristor	3 Thyristor 3 Diode
0.415	8	12	--	14	10
6.6, 11	85	130	250	150	100

If the rating of the source is higher than the limits specified, a current limit of each harmonic at various system voltage levels is specified. These seem to be very liberal limits, e.g., the third harmonic current at 415 V is limited to 34 A. However, it is desired that the harmonic voltage distortion limits at any point on the system, including the background levels, may not exceed the levels specified in Table 6-7.

g. Australia. The harmonic voltage distortion limits at any point on the system are specified. They are generally the same as in the Table 6-7 for the UK system.

If the harmonic source is connected to a bus where the harmonic levels are less than 75% of the above levels, then the allowable size of the harmonic source is related to the available short-circuit capacity at the point of connection. As an example, for a short-circuit level of 100 MVA, a 6-pulse uncontrolled rectifier size of 1000 kVA is allowed.

Table 6-7. Limits on System Harmonic Voltages (UK)

Supply System Voltage kV	Voltage Distortion Factor (DF), %	Individual Harmonic Voltages V_n , %	
		Odd	Even
0.415	5	4	2
6.6, 11	4	3	1.75
33, 66	3	2	1
132	1.5	1	0.5

h. Finland. The Finnish recommendation unlike some others, specifies a harmonic current percentage limit based on a reference current which is the current corresponding to an average hourly power. For voltages 3 to 20 kV, each harmonic current is limited to 8% of the reference current and the distortion current ($\sqrt{\sum_{n=2}^{\infty} I_n^2}$) is limited to 10% of the reference current. In case these current limits are exceeded, the harmonic producing source is still acceptable if the system voltage distortion is less than 5% with each harmonic voltage being limited to 4% of the fundamental. There are different voltage limits specified for various system voltage levels.

3. Existing U.S. Utility Practices on Harmonics, New York State Electric & Gas Corporation, September 1979.

A survey of existing U.S. utility practices on harmonics was carried out by New York State Electric and Gas Corporation in September 1979. Out of 78 questionnaires and 62 replies, only one utility had a formal specification for the injection of harmonic voltages which the customers had to meet. The limits specified were 2% (of fundamental) for any one frequency and a voltage distortion factor (DF) of 4%. Two companies had guidelines based on telephone interference factors. Some companies were proposing maximum harmonic levels for customer-owned generation. The proposed limits on the DF from each source ranged from 3-10%. Some companies suggested values which might be representative of the maximum tolerable harmonic voltage levels. They ranged from a DF of 2-5% and limit on each individual voltage of 1-3%.

4. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

Regarding harmonics, the guidelines are as follows:

- (1) Adequate design precautions must be taken by the owner to prevent excessive and deleterious harmonic voltages or currents caused by the production facility from occurring on the connecting electric system.
- (2) The production facility must be designed to operate with normal harmonic voltages and currents that originate from the connecting electric system.

The guidelines are not specific on what an excessive harmonic voltage or current is.

5. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

Several alternative standards limiting QF harmonics were identified:

- (1) Require that the rms (square root of the sum of the squares) harmonic content be equal to or less than some percent (such as 10%) of the fundamental.
- (2) Develop limits for each individual harmonic wave; for example, limit the third harmonic to 5% of the fundamental.
- (3) Retain the general requirement that a QF shall not adversely affect other customers or the interconnected utility, and if a problem occurs, that QF will be disconnected until the QF customer corrects the problem.
- (4) Negotiate a solution with a QF when a problem is identified. The solution could include isolating the QF through a distribution transformer, installing capacitor banks, or requiring the customer to modify the QF system to resolve the problem.
- (5) Require that the quotient of the sum of the maximum instantaneous values of all harmonics, divided by the fundamental, be less than some specific percentage. This method is simple to calculate but difficult to evaluate as the sum ignores time relationships between harmonics. Also, this method results in a significantly higher value than is derived from alternative 1.

Any standard should differentiate between current harmonics and voltage harmonics.

Generally, alternative 3 would provide flexibility in dealing with unforeseen situations. For a few, small, randomly-located QFs, alternative 1 with an arbitrary percent for current harmonics and voltage harmonics may be more desirable. Initially a 10% limitation for current harmonics and a 2% limitation for voltage harmonics may be sufficient.

When large numbers of QFs are connected, the standards should be reevaluated.

6. IEEE Guide for Harmonic Control and Reactive Compensation of Static Power Converters, IEEE Project #519, July 1979.

These guidelines were established in 1979. There are detailed guidelines for telephone interference parameters (such as the voltage telephone interference factor and the I-T product). There are also limits for the DF provided for various system voltages. For a 460-V system, the limit specified is a DF of 5%. There are no limits specified for individual sources of harmonics. Also, limits on individual harmonic frequencies are not provided.

Besides the distortion factor, another parameter specified is the area of the commutation notch in volt-microseconds. The commutation notch is partly responsible for the generation of high frequency noise on the system. For a 480-V system, the limits on the commutation notch are 17,500 V sec.

7. Guidelines on Telephone Interference

The guidelines regarding telephone interference are very well established. It is unnecessary to detail these guidelines because the following references provide that.

- (1) The Telephone Influence Factor of Supply System Voltages and Currents, Supplement to Engineering Report No. 33, EEI Publication 60-68, September 12, 1960.
- (2) Ball, W. C., and Poarch, C. K., "Telephone Influence Factor (TIF) and its Measurement," Transactions AIEE, pp. 659-663, January 1961.
- (3) Kimbark, E. W., Direct Current Transmission, Wiley & Co., 1971.
- (4) IEEE Guide for Harmonic Control and Reactive Compensations of Static Power Converters, IEEE Project #519, July 1979.

D. CONCLUSIONS

- (1) Few utilities around the country have any guidelines or specifications regarding harmonics. Most utilities would disconnect the dispersed generator if it generated excessive harmonics which created problems.
- (2) There are many European guidelines available. It is not clear if they would apply for a reasonably high penetration of PV sources.
- (3) Very limited information exists on the maximum tolerable limits of harmonics (both current and voltage) for various appliances and power system equipment. There is some disagreement between the few sources of data available on the subject.
- (4) Little effort has been made to measure the background harmonic level on the present day power systems.
- (5) To summarize the various guidelines/standards/specifications on harmonics, a 5% system voltage distortion factor with a limit of 3% on any single voltage may be acceptable. (It is the system voltage distortion factor at any point on the system and not due to an individual source.) However, there is so much variation between the various guidelines that this number may be meaningless.
- (6) Some software is available to study the interaction of harmonic sources with the system. Although most of the software was developed for large isolated sources, it may be possible to use it for an initial study of PV systems.
- (7) The factors to determine telephone interference are well established and do not need further study.
- (8) The problem of EMI (both conducted and radiated) must be investigated to determine conformity to FCC regulations.

E. RECOMMENDATIONS

To resolve the issue of harmonics, a plan of action is presented, in flow-chart form, in Figure 6-3. This applies only to a study of low frequency harmonics. The problem of impulsive noise and EMI must be investigated separately. The status of the various tasks outlined in Figure 6-3 is shown in Table 6-8.

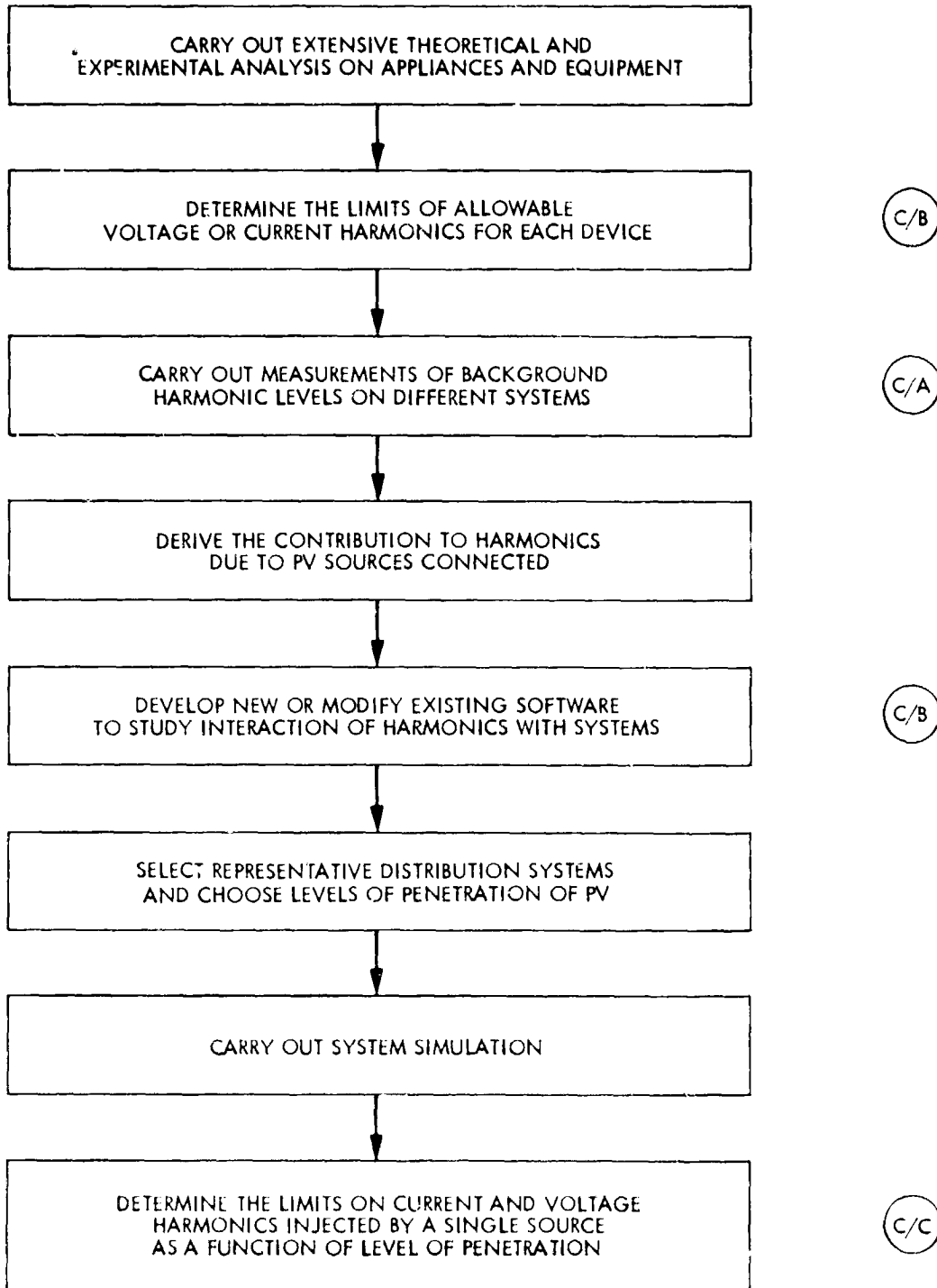


Figure 6-3. Flow-Chart Representative of the Plan for Resolving the Issue of Harmonics

Table 6-8. Harmonics: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Tolerable harmonic levels	C	B	8
Measurements of background harmonic levels on systems	C	A	2,13
System software to study interaction	C	B	14
Specify limits for individual sources	C	C	-

A	The issue is completely resolved or can be resolved when based on available knowledge.
B	Much is known or documented, but the issue is not totally resolved.
C	Very little is known or documented.
D	Nothing is known or documented.

SECTION VII

SAFETY AND CODE REQUIREMENTS

A. INTRODUCTION

1. Definition

This includes development of safety requirements for PV systems connected to the utility power system. The object is to minimize the potential of a shock hazard to either the owner of a PV system, or to the utility operating personnel, and to also prevent the possibility of destruction of property from a fire hazard.

2. Risk

Unless appropriate requirements are established within the existing framework of product safety standards, building and electrical codes, and utility codes, it will be very difficult to obtain the necessary approval from either the utility or local code enforcement officials.

3. Discussion

It is highly important that PV systems connected to a utility system should not cause any safety hazard to either the PV source owners or to utility personnel. The safe installation of residential, commercial, and industrial electrical systems is guided by the National Electric Code (NEC), which is published by the National Fire Protection Association (NFPA) every 3 years. The code, as written now, does not address photovoltaics. It is anticipated that revisions to the NEC will emphasize the unique aspects of photovoltaics and address those concerns which could result in an unsafe installation. Some issues of concern are grounding of PV arrays and the Power Conditioning Subsystem (PCS), electrical isolation (through a transformer) of the PV system from the utility system, disconnection of the PV array from the PCS and the PCS from the utility during times of maintenance. These and other issues directly impacting safety must be thoroughly analyzed and included in any revision of the code.

B. REFERENCES

1. Photovoltaic Utility/Customer Interface Study,
Final Report, Westinghouse Electric Corp. for
Sandia, under Contract #13-2228, December 1980.

Chapter 2 discusses the possible methods of interconnecting residential PV systems with the utility and their acceptance under the NEC. Of three methods discussed, one method violates the code while the other methods can comply with the code. The report also tabulates the list of typical protection devices required for the interface, assuming, however, that the Power Conditioning Unit (PCU) is provided with its own protection. The requirements of grounding PV systems are also briefly discussed based on articles of the NEC describing various grounding practices.

Although some interesting comments are made about the applicability of PV systems to NEC, the treatment is very brief.

2. Study of Dispersed Small Wind Systems Interconnected with a Utility Distribution System, Interim Report, by Systems Control Inc., Department of Energy Contract #DE-AC-04-76DP03533.

This study concluded that the utilities' work procedures were adequate for ensuring line-crew safety with customer-owned, wind turbine generators connected to distribution systems. These procedures require that synchronous generator and self-commutated inverter small wind systems provide a disconnect switch, accessible to the utility's line crew, to disconnect these generators during repair periods. Line-commutated inverter and induction generator small wind systems are not addressed by these same work procedures because these systems are voltage-dependent.

The examination indicates no deficiency in hardware for disconnecting the customer's wind turbine generator. Many hardware options for disconnecting the wind turbine generators exist. These options are available to the utility and to the owner/designer of the wind turbine.

The study does not examine the possibility of self excitation of line-commutated inverters and induction generators nor does it emphasize the applicability of the various codes (such as NEC) to dispersed generation.

3. Meeker, D. G., and Weinstein, A. S., Exploratory Study, Safety and Liability Considerations for Photovoltaic Modules/Panels, Carnegie/Mellon University, Report No. DOE/JPL 955846-81/1, January 1981.

This report explores generic types of hazards. It offers methodologies for analysis that can be devised to enhance safety and reduce liability in using PV energy sources.

The report suggests areas for which hazard assessment should be undertaken, including: manufacturing and assembly, shipping and handling, operation and maintenance, installation, natural events, and others. It is concerned with the need for an automatic disconnect between the PV system and the utility's lines when the utility suffers a complete loss of power.

Also, there is a problem if a significant feed from a large number of PV arrays is suddenly lost due to a natural event or other cause. In this case, the utility may not be able to pick up the load caused by loss of the PV source to avoid either a blackout or a rapid drop in voltage. When significant damage occurs, the question of responsibility and liability, will arise. The report does not give answers, but poses issues to stimulate consideration.

4. Standard of Safety: Flat Plate Photovoltaic Modules and Panels, Construction Requirements, Vol. I, JPL Report 5101-164, Low Cost Solar Array Project, January 15, 1981.

This report contains interim safety construction requirements for PV modules and panels that are compatible with system safety considerations identified by building and electrical codes.

These requirements cover flat-plate photovoltaic modules and panels intended for installation on or integral with buildings (free-standing, not attached to the buildings).

The report also covers components intended to provide electrical connection to, and mounting facilities for, flat-plate photovoltaic modules and panels.

5. Interim Standard for Safety: Flat-Plate Photovoltaic Modules and Panels, Volume II: Performance Requirements, JPL Report 5101-164, Low Cost Solar Array Project, January 1981.

This volume contains interim safety performance requirements for PV modules and panels. These requirements are primarily in the form of test procedures and methods presently being considered to verify compliance with the construction requirements set forth in Volume 1.

The performance requirements are of a very rudimentary nature at this time. The scope is limited to safety aspects of module and panel performance. This volume contains a number of environmental endurance tests to assess possible degradation of safety features associated with environmental exposure of a PV panel or module during its design life.

6. Investigate Protection of Electric Distribution System Containing Decentralized Generating Devices, RFP PEDS-19, Oak Ridge National Laboratories for the Department of Energy.

The final study task (see also Section II-E) involves an analysis of personnel safety. Current practices will be reviewed and modifications suggested. Hardware requirements to meet safety modifications will be discussed.

7. Investigation of a Family of Power Conditioners Integrated Into the Utility Grid, DOE Contract DE-AC02-79ET 29359 with Westinghouse Electric Corporation, Draft Final Report, January 1981.

This study recommends that an isolation transformer be used to couple the converter to the utility power system because the dc source can then be grounded at any desired point without any problems. If the array is not firmly grounded, a virtual ground will occur at, or close to, the mid-point of the array. This virtual ground can undergo considerable voltage excursion (up to the peak converter ac voltage) with respect to the true earth ground. The same holds true if no isolation is used with a bridge configuration converter. The dc source becomes grounded by the ac system ground only if a non-isolated midpoint converter is used. Such a practice, however, may not be acceptable.

It is also recommended that the only direct connection from the ac system ground to the conversion equipment be the case of the converter.

It is suggested that any converter should automatically cease to function, just as a line-commutated converter does, in the event of an ac supply fault followed by a protective device clearing. This can be accomplished easily if unity power factor converter operation is the norm, and with somewhat more difficulty if it is not.

8. DOE/PV Sponsored Studies with Underwriters Laboratory (UL).

Currently there are two DOE/PV sponsored studies going on at Underwriters Laboratory to investigate the grounding and safety requirements for the PV array and the PV Interface Subsystem. The studies are managed by JPL and SERI respectively. Hopefully, at the completion of the studies, viable safety requirements will be developed to ensure adequate safety to the PV owner and to utility personnel.

9. Interim Performance Criteria for Photovoltaic Energy Systems, Final Report, SERI/TR-742-654.

This document is an initial attempt at setting performance criteria for photovoltaic systems. Because of the evolutionary nature of performance criteria, updates should be expected. The criteria apply to the system as a whole and its subsystems. Over 50 references are cited to give further background information.

C. GUIDELINES/STANDARDS

1. National Electric Code (NEC), published by the National Fire Protection Association (NFPA).

This guideline is followed extensively by local code enforcement officials for approval of electrical installations.

2. National Electric Safety Code (NESC), ANSI C2-1981.

This standard is published by the IEEE. It is applicable to the systems and equipment operated by utilities, or similar systems and equipment of an industrial establishment under the control of qualified persons.

3. Standards for Operating Reliability, California Public Utilities Commission Draft Report, Chapter 14.

For various issues regarding safety, the PUC staff gives the following recommendations:

- (1) Except for the utility manual disconnect and feeder reclose blocking equipment, the QF shall have the option of owning, (furnishing and installing) operating, and maintaining the interconnection protective equipment or paying for the utility to install the equipment and maintain it.

- (2) The utilities shall review their requirements for small size facilities to simplify requirements and standardize. Dedicated transformer requirements that the QF may be required to pay for shall be limited to no greater than 1.15 times the QFs generator nameplate capacity. Daily logs of generator trips and separations for small QFs shall not be required by the utility.

4. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

The safety and grounding guidelines are:

- (1) In order to provide safety for the connecting electric system employees performing emergency repairs or routine maintenance to its lines, the owner must provide equipment for disconnecting and isolating the production facility during electric system interruptions. Such equipment must be capable of preventing the production facility from energizing the systems lines during such interruptions. It must include a device (or devices) which the electric systems employees can operate and lock to isolate the production facility and all means of backfeed into the connecting electric system.
- (2) The facilities (generator, connecting transformer, etc.) that connect to the electric system must be grounded so that coordination is maintained with the relay protection system used by the connecting electric system and so that the connecting facility is not subjected to deleterious voltages during fault conditions.

No mention is made of any isolation transformer.

5. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

The specific guidelines provided for safety, isolation, and grounding are as follows:

- (1) A utility controlled device (switch) which physically and visually opens the circuit to the QF, must be provided. The device:
 - (a) Must open all cables to the device including the neutral.

- (b) Must be operable by utility personnel at any time without notice to the QF and without restricted access.
- (c) Must be lockable in the open position by the utility.

The disconnecting switch should simultaneously interrupt all phase and neutral cables between the utility and QF generation. Under energized conditions, this will preserve the electrical continuity of all cables interconnecting the utility and QF and prevent voltage problems and safety hazards that could occur if electrical continuity was not preserved.

The proliferation of QFs on a utility's system could significantly impact the manpower (and other costs) required to disconnect and lock out QFs from the utility's system for outage clearance, construction, and maintenance purposes.

Also, a utility should review and revise, as necessary, its operation, safety, and hold tag procedures (field and dispatching manuals) in light of interconnections with QFs.

- (2) Without respect to local building codes, the NEC, article 250, covers grounding and bonding of electrical installations. This article also includes specific requirements for the following:
 - (a) Systems, circuits, and equipment required, permitted, or not permitted to be grounded.
 - (b) Circuit conductor to be grounded on grounded systems.
 - (c) Location of grounding connections.
 - (d) Types and sizes of grounding and bonding conductors and electrodes.
 - (e) Methods of grounding and bonding.
 - (f) Conditions under which guards, isolation or insulation may be substituted for grounding.
 - (g) Connections for lightning arresters.
 - (h) Grounding of dc circuits.

Grounding requirements should be in compliance with ART-250 of the NEC and any applicable local codes.

- 6. San Diego Gas & Electric Company, Protection and Operation Guidelines for Cogenerators and Small Power Products, Preliminary Draft submitted to California PUC, 1980.

The excerpts from the draft guidelines applicable to safety considerations are as follows:

- (1) A means of disconnection under the control of utility shall be applied to all customers with parallel generation. This can be applied on either the primary or secondary circuit and accomplished with switches, load break elbows, cutouts or secondary breakers. As existing circuit design incorporates these features, additional costs should be minimal.
- (2) When service is provided at or below 480 V, the customer is served by a dedicated distribution transformer.
- (3) The customer's installation must meet all applicable national, state, and local construction and safety codes.
- (4) Transformers feeding customers with parallel generation shall be identified with a special tag attached to the transformer or pole. This will notify field crews of the possibility of backfeed. Incoming load data sheets should be flagged and used to initiate order to tag poles.

7. Operating, Metering, and Protective Relaying Requirements for Parallel Operation by Small Cogenerators and Power Producers, 100 kW or Less, Pacific Gas & Electric Company, Draft submitted to California PUC, September 1980.

The excerpts from this guideline regarding safety are:

- (1) In all cases, a PG&E-owned, manually operated disconnect device, which can be opened for line clearances, must be provided. Usually, this will be an air switch or fused cutout on the high-voltage side near the transformer which connects the seller's generator to the PG&E system.
- (2) All generators 5 kW or greater must be connected to the PG&E system through a dedicated transformer. Generators less than 5 kW, generating at the system voltage level, may not require a transformer. However, this must be approved by PG&E after review of the project details.

D. CONCLUSIONS

- (1) Of the utilities surveyed, PG&E did not require a dedicated transformer for dispersed generators 5 kW and below, and SDG&E did not require a dedicated distribution transformer for 10 kW and below. The terminology used by the utilities is quite confusing. When referring to dedicated distribution transformers, it is not clear whether they are referring to an isolation transformer or something in addition. These terms must be clarified.
- (2) The requirement for a visible manual disconnect is universal. For a large penetration of dispersed generators, the practicality of such a requirement is questionable. Instead, there may be a requirement for a group of DSGs rather than individual disconnects.
- (3) The possibility of self-excitation of line commutated inverters and induction generators and thus, their ability to feed the system during the loss of utility power must be investigated.
- (4) Although some of the articles of the NEC and NESC may be applicable to PV systems, the code must be revised to cover various aspects of PV system installation and interconnection to the utility. Such revisions could help local electrical inspectors and utilities approve interconnection of PV systems and minimize the potential for inconsistencies which could result from individual interpretation of the code.

E. RECOMMENDATIONS

Figure 7-1 is a recommended plan of action for resolving the various problem areas. Table 7-1 shows the status of the various problem areas.

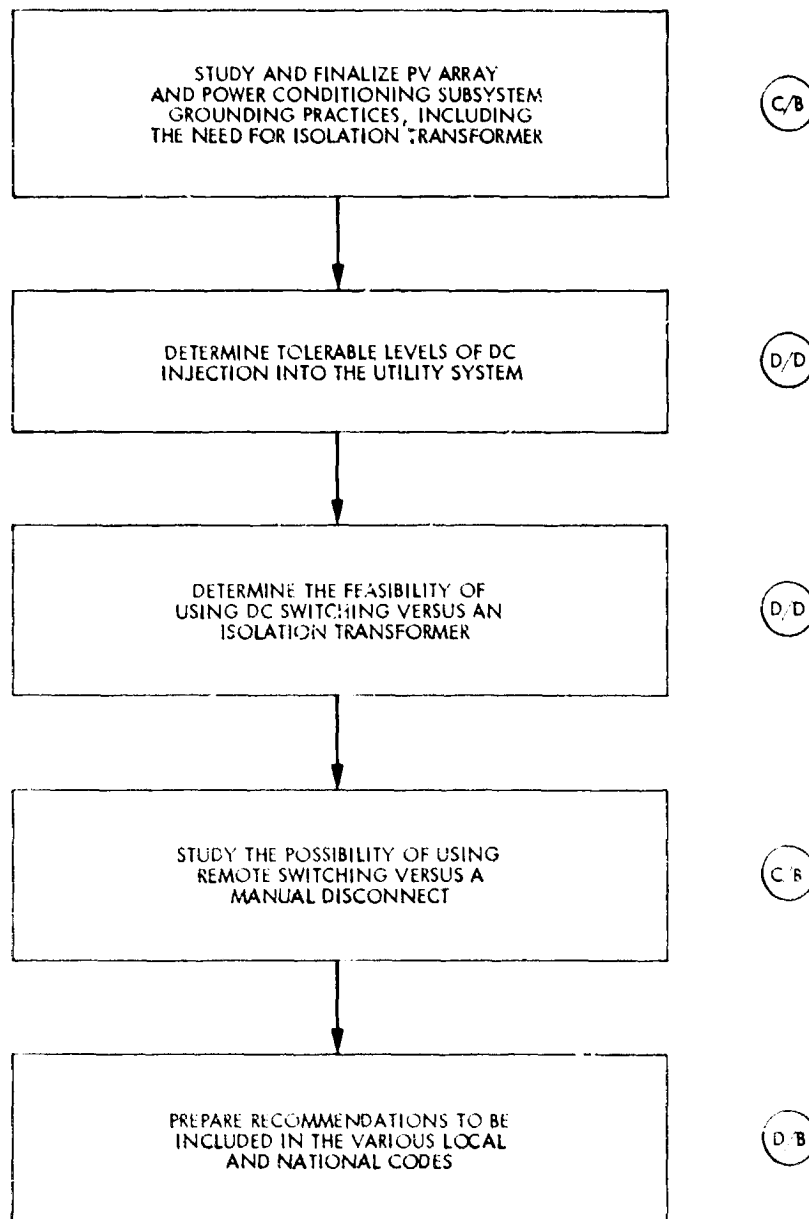


Figure 7-1. Flow-Chart Showing a Recommended Plan of Action for Resolving the Issue of Safety and Code Requirements

Table 7-1. Safety and Code Requirements: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Grounding Requirements	C	B	8
Tolerable Levels of dc Injection	D	D	-
Feasibility of dc Switching vs Isolation Transformer	D	D	-
Remote Switching vs Manual Disconnect	C	B	-
Recommendations for Modifications in Codes	D	B	a

- A The issue is completely resolved or can be resolved when based on available knowledge
- B Much is known or documented, but the issue is not totally resolved.
- C Very little is known or documented.
- D Nothing is known or documented.

^aAt the present time, the NEC Correlating Committee has approved the formation of two ad-hoc subcommittees to address code-related issues associated with photovoltaics and cogeneration. Their input will be considered for incorporation into the next edition (1984) of the NEC. Proposals from each ad-hoc subcommittee must be received no later than September 30, 1981.

SECTION VIII

METERING REQUIREMENTS

A. INTRODUCTION

1. Definition

Metering requirements are the modifications in the revenue metering needs so that the exchange of energy between the PV system and the utility can be accurately measured for billing purposes.

2. Risk

Present day induction disk type meters are generally sensitive to only the fundamental component of the total power (or energy) and would be in error when used under non-sinusoidal conditions.

3. Discussion

Presently in the residential sector, the only quantity which is generally metered by the utilities is kWh of electrical consumption. For some bigger industrial and commercial customer, quantities such as kW, kVA, and kVAR demand, along with time of day kWh (TOD) consumption, may also be metered. Once PV sources are installed, the metering needs will be modified considerably. Some of the options which need to be considered are:

- (1) Measuring the net amount of energy consumed or delivered by the PV residence. This would require only one kilowatt-hour meter. This method could only be employed if the buy-back rates by the utility were the same as the selling rates and if no time-of-day metering was used.
- (2) Using separate directional watt-hour meters to measure the energy delivered by the utility and energy consumed by the residence. This would not impose any restriction on the buy-back rates.
- (3) The same as (2), plus another meter to measure the net VARH consumed by the residence. This option would be employed only if the utility expressed concern about the bad power factor of PV power conditioning units.
- (4) Some combination of the above options, but with time-of-day rates. This would necessitate using meters which are either internal-clock-actuated or actuated by the utility from some central command station. This would be the most expensive metering option.

There could be more options in which the energy consumption and the demand (kW or kVA), could be measured as a function of time. These would increase the complexity of the metering requirements and might not be practical if a large number of residences were employed.

It is important to consider the effects of wave distortion on the measurement of the different quantities. The present day induction disk-type meters are generally sensitive to only the fundamental component of real or reactive energy and could be in error if excessive wave distortion were present. In the absence of suitable meters which could function accurately under non-sinusoidal conditions, proper calibration factors must be developed for present day meters to make them compatible with PV systems.

B. REFERENCES

1. Measurement of Harmonics, ongoing DOE/EES contract with the National Bureau of Standards (NBS), Contract #AC01-80RA-50215.

This is a continuing project with funding first received from the DOE in April 1980. Preliminary design work at NBS started earlier in FY 1980. The program consists of two main tasks: (1) developing methods and associated instrumentation to accurately measure electrical power in highly distorted waveforms (specifically, a sampling type wattmeter with $\pm 0.1\%$ accuracy, traceable to the basic NBS standards, will be developed and one prototype built), and (2) developing methods and the necessary physical standards to accurately characterize and calibrate wideband, high-current shunts utilized in electric power train systems. An NBS-designed impedance bridge will be modified to provide an uncertainty of $\pm 2\%$ or better in the value of these transducers of over the frequency range from dc to 100 kHz.

In FY 1980, an improved simulation program for wideband sampling was developed, with an analysis of the major sources of error due to two-channel sampling, digitizing, and signal processing. Assembly and initial check-out was completed for the 16-bit microcomputer and associated peripheral devices display, direct-memory access (DMA) multiplier-accumulator, etc., comprising the digital signal processing hardware of the prototype wattmeter. Current shunts submitted by NASA Lewis Research Center (LeRC) were tested over the frequency range from 400 Hz to 10 kHz. The performance was different than expected from a well-designed coaxial resistor.

2. Fuchs, E. F., Impact of Harmonics on Home Appliances, Interim Report, performed for DOE/EES under contract DE-AC02-80RA50150.

This report documents the effects of harmonics on single phase watt-hour meters. The major effect of harmonics on residential appliances is to increase the power flow to these devices. This increased power flow appears as increased losses in all appliances except those which include resistive heating elements (i.e., stoves, electric frypans, etc). The watt-hour meter records part of this increased flow but not the entire amount.

Thus, two issues are raised by the report. First, should the watt-hour meter accurately record these harmonics or, second, should the meter measure only that power which can be used by the appliances (only the fundamental). These issues are under further consideration by DOE/EES.

3. Electrical Interference to Standard Induction Watt-hour Meters, ongoing EPRI, Project RP 1738.

The study objective is to determine the response of standard watt-hour meters to various harmonics by experimental analysis. The study results are expected by June 1981. Honeywell is the project contractor.

4. Development of an Electronic Single-Phase Watt-hour Meter, ongoing EPRI Project RP 1420.

The study objective is to develop an electronic watt-hour meter with three registers for time-of-day metering for load control and automatic meter reading by the utility. The meter would measure energy up to about the 100th harmonic. The study should be completed by the end of 1982. McGraw Edison Company is the primary contractor with Texas Instruments as the subcontractor.

C. GUIDELINES/STANDARDS

1. Operating, Metering, and Protective Relaying Requirements for Parallel Operation by Small Cogenerators and Power Producers 100 kW or less, Pacific Gas & Electric Company, Draft submitted to California PUC, September 1980.

Excerpts from this guideline relating to metering are:

- (1) All deliveries of power between a seller and PG&E must be metered as a basis of determining payments between the parties. All meters must prevent reverse registration so that deliveries to and from the seller can be separately recorded and treated as separate transactions under the applicable rate or price schedule.

- (2) The seller will provide, subject to PG&E approval, all facilities required to accommodate any meters, which may include either standard watt-hour meters or time-of-delivery metering depending upon the contractual agreement.

Metering requirements for the delivery of power to PG&E will fall under two general classifications, depending upon the contractual arrangements:

- (1) Surplus sale, where only the excess of the seller's generation is delivered to the PG&E system after the seller's normal service requirements are satisfied. PG&E will provide standby and supplementary service in accordance with applicable electric tariffs on file with and authorized by the California Public Utilities Commission.

An "out" meter(s) will be required to measure the seller's surplus generation which is capable of delivering power into the PG&E system. Such delivery shall be at the established service voltage.

- (2) Simultaneous purchase and sale, where the entire net output of the Seller's generating facility is capable of delivering power to the PG&E system while PG&E simultaneously supplies all of the seller's normal electric service requirements.

All "in" meters will be required to measure energy supplied to the seller for his generator auxiliary load when his generator is not operating and during periods of generator start-up and shut-down. "Out" meter(s) will be required to measure energy delivered to the PG&E system. Such delivery shall be at the established service voltage.

2. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

Metering for billing purposes must, at the very least, measure the net amount of energy purchased from the QF or sold to the QF by the utility. (Note: Low power factor QFs may deliver kWh to the utility while simultaneously drawing kVAR from the utility.)

The concept of simultaneous deliveries to the utility by QFs and to the QFs by the utility will require more complex metering installations. Metering requirements will be impacted by the physical location of the QF generation interconnection with the utility system as related to the location of the QF load connection to the utility.

The requirement to purchase from a QF does not automatically imply that the utility will sell to the QF. The utility is obligated to sell to the QF only if the QF requests such sale. Metering requirements should be dictated

by and dependent upon the needs and desires of the QF, the utility and regulatory authorities. But, reasonable metering costs associated with QF generation can be imposed on the QF.

The need for precise information concerning the time of delivery of electric energy should be carefully considered. It should be recognized that electric energy and capacity may have a different value dependent on incremental deliveries, i.e., energy required during a peak period of the day when a high running-cost generator must provide energy needs above that provided from less expensive generation during off-peak periods.

The QF and the utility can agree on purchase rates under terms and conditions which are less than the maximum allowed by FERC rules. Accordingly, certain parameters, particularly when related to capacity value, may be estimated instead of precisely determined on the basis of metered data.

D. CONCLUSIONS

- (1) Metering requirements for a PV system are a function of the utility rate structure for dispersed generators and depend upon the particular utility and the proper regulatory authorities. If the utility offers many options, the PV system owner will decide the best option based on a cost/benefit assessment.
- (2) As PV systems will produce (or consume) real and reactive power at frequencies besides 60 Hz, it is not clear whether (or how) this component of power would be measured. The commonly used induction type meters for measuring real and reactive energy are generally sensitive to only the fundamental component. Presently, the utilities have shown little concern for this particular issue.

E. RECOMMENDATIONS

Because the results from DOE and EPRI sponsored studies are unavailable as yet, no recommendations for further work are provided.

SECTION IX

OPERATIONS

A. INTRODUCTION

The most important objective in operating an electrical power system is to maintain continuity and quality (frequency and voltage, etc.) of service to the customers. This implies that the generation must be adjusted in real time to match the prevailing demand. Another objective to be achieved as long as it is consistent with continuity of service and dependable operation is to distribute the total generation among the various generating units in the most optimal way to minimize the overall cost. Because of regulatory actions, a practice of dispatching generation to some criteria based on air quality is in effect at some utilities (e.g. : NO_x dispatch).

The problem of power system operations can be further categorized, based on the time span of interest, as shown in Figure 9-1. Each category is discussed below.

B. AUTOMATIC GENERATION CONTROL

1. Definition

Automatic Generation Control (AGC) is the regulation of the output of electric generators within a prescribed geographical area. This is to maintain the scheduled system frequency and/or the established interchange of power with other areas within predetermined limits.

2. Risk

With a large penetration of PV systems, fluctuations in PV output could cause excessive swings in system frequency unless proper control action is initiated.

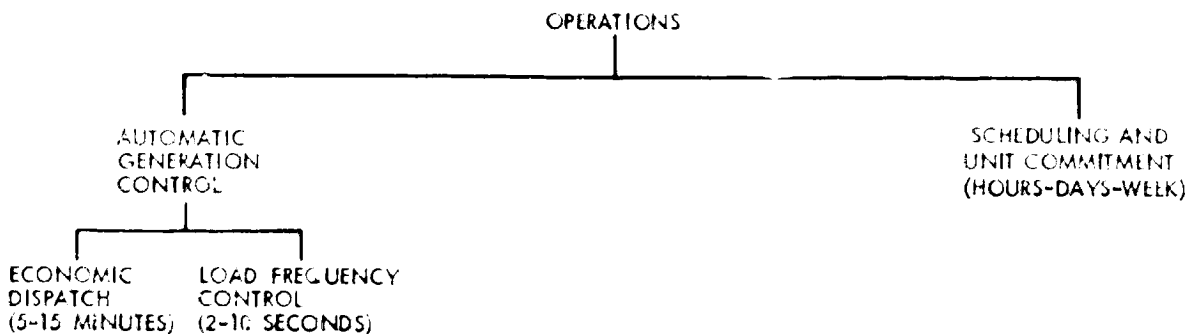


Figure 9-1. Power System Operations

3. Discussion

The load on a utility power system fluctuates constantly and the generation must be ramped up and down to meet the ever changing load demands. This implies that utilities should have enough generating units on-line, capable of load following (changing their generations to meet the variable load demand). Any change in system load results in a momentary change in system frequency. The magnitude and duration of this change of frequency is dependent on many factors such as inertia of the system, magnitude of the disturbance, and the control action employed, etc. It is highly important that these frequency fluctuations which would result in malfunctions of frequency sensitive devices such as clocks, relays, etc., be kept to a minimum.

Because a PV plant output varies continuously (usually a smooth variation, but sometimes a severe fluctuation because of the weather pattern) it will have a direct impact on the Automatic Generation Control requirements. The greater the PV penetration in a utility system, the greater control requirements (such as more units capable of load following) will be. This will certainly have a cost impact as well as an impact on the performance of the system. This could limit the maximum penetration of PV sources on any given system, but is not expected to be a real factor until a significant amount of PV generation compared to total system generation is used.

C. ECONOMIC DISPATCH

1. Definition

Economic Dispatch Control (EDC) is the distribution of generation requirements among alternative sources for optimum economy.

2. Discussion

It seems unlikely that this issue will pose any major problems to the introduction of PV other than modifications in control requirements. As PV systems have essentially zero incremental costs, they must be dispatched first. The conventional units will then be dispatched economically to serve the remaining load.

D. SCHEDULING AND UNIT COMMITMENT

1. Definition

Scheduling is the commitment of various generating unit a few hours to a day in advance to meet the expected load usually based on economic considerations. Generally, unit commitment covers a broader period (up to a couple of weeks) and is usually based on the expected availability of various units.

2. Risk

As the amount of PV generation cannot be accurately predicted in advance, some allowance in terms of increased spinning reserve and standby generation may have to be made.

3. Discussion

Determination of the generating capacity to be operated for a given total load by the utility is based on the following:

- (1) Economic evaluation.
- (2) Reserve requirements.
- (3) Stability limitations.
- (4) Voltage limitations.
- (5) Ability to pick-up load quickly.

The uncertainty associated with PV generation will impact all these considerations in varying proportions. The impact will be a direct function of PV penetration: the greater the penetration, the greater the impact will be. The impact could probably be lessened by a real-time weather monitoring system which could warn the system operator ahead of the time of impending weather conditions.

E. REFERENCES

1. Kirchmayer, Leon K., Economic Operation of Power Systems, John Wiley & Sons, New York, 1958.

This book presents theory and practical applications involved in determining the economic operation of a power system. It develops the necessary circuit and mathematical techniques required in addition to describing the important role that computers can play in improving power system performance. A large part of the book is devoted to methods of calculating transmission line losses through transmission-loss formulas.

The methods in this book have been widely applied by electric utilities in the United States and Canada resulting in significant savings in fuel costs.

2. Cohn, Nathan, Control of Generation and Power Flow on Interconnected Systems.

This is one of a few books available on the subject. It discusses the theory, advantages, and responsibilities of different companies interconnecting to form power pools. The governor characteristics and their role in Automatic Generation Control (AGC) are discussed. Area regulation and regulation as a function of bias are discussed in depth. The theory of economic dispatch is briefly covered. Methods for determining transmission losses are described. Block diagrams of control systems to achieve economic dispatch, area regulation, etc. are also discussed.

3. Lee, Stephen, and Yamayee, Zia, "Load-Following and Spinning-Reserve Penalties for Intermittent Generation," IEEE Paper No. 80 SM 582-7, IEEE-PES Summer Power Meeting, July 1980.

In this study, it is demonstrated that the increased requirements can completely eliminate the usual energy and capacity credits because of PV systems. At lower levels, the increase in load-following and spinning-reserve is fairly linear with some energy and capacity credits found. The study, however, did not use a method which chose the mix optimally; screening curves were used. There are also some questions on the probabilistic dispatching scheme.

4. Schweppe, Fred C., Economic Scheduling of Distributed Storage and Generation, not published.

This is an excellent first step toward determining the effects of intermittent generation upon the strategy used to dispatch units. It assumes that a unit commitment and maintenance schedule have already been developed for the coming week. Once done, the study states three major findings:

- (1) The effect of stochastic local variations in microweather patterns (cloud cover, wind gusts) on small solar and wind units can be ignored at the central dispatching office, independent of the number of units. This result is based on the assumption that the variation in the weather at this small local level is statistically independent over the geographical area served by the central dispatching office.
- (2) The effect of global variation in macroweather patterns (storm fronts) on solar and wind units is very important at the central dispatching office unless the number of units is small. In this case, the weather variations are dependent upon each other and, thus, effect the result.
- (3) Highly accurate scheduling is not required/justified for small dispersed units. This is based on a wide distribution in system

λ so that the optimum scheduling is obvious and the fact that a small intermittent unit is involved so that a small amount of energy is injected into the system.

5. Graham, et al, "Effects of Battery Storage Devices on Power System Dispatch," No. 80 SM 535-5, presented at the IEEE PES Summer Power Meeting, 1980.

Battery models and rectifier inverter models were developed for the hybrid simulator at the University of Missouri-Columbia. Dispatching software was designed to allow test runs to use a variety of dispatching algorithms. It was shown that batteries can be dispatched to aid regulation and peak shaving.

This study is not directly applicable to PV since batteries are a constant source. PV is variable and cannot be dispatched as easily.

6. Fegan, George, and Percival, C. David, Problems in the Integration of Intermittent Sources into Utility Production Costing Models, No. SERI/TP-351-546.

The intermittent generation source, a source over which the utility dispatcher has minimal control with regard to power availability, presents serious problems. The problems are separated into those renewable resources which are correlated to the demand and those which appear to act independently of demand. Approaches to solutions are explored.

F. GUIDELINES/STANDARDS

No guidelines or standards could be located on this particular issue.

G. CONCLUSIONS

- (1) The introduction of PV systems into the utility grid is not expected to have a substantial impact on system operations until the penetration is quite high. This is probably the main reason for the absence of sufficient, relevant literature on the subject.
- (2) The impact on system operations will probably be more of economic concern rather than of technical concern. Any technical impacts will probably be limited to investigating better predictive techniques and control, and communication alternatives.

H. RECOMMENDATIONS

Because this is a long-term issue expected to impact a high level of system penetration, no recommendations for further work are provided at this time.

SECTION X

DISTRIBUTION SYSTEM PLANNING AND DESIGN

A. INTRODUCTION

1. Definition

Modifications are needed in the distribution system planning and design process of conventional distribution systems so that the integration of PV systems can be accommodated successfully.

2. Risk

- (1) By not planning for consideration of PV, the integration of PV must occur through actions in the design phase only. Thus, the lead time for utility design is shortened with fewer options available to enable the integration to occur successfully.
- (2) By not considering PV in design efforts in advance of need (such efforts may be triggered by an entrepreneur installing PV), the early and highly visible projects may accidentally demonstrate that PV is more trouble than it is worth.

3. Discussion

The lack of consideration of large local penetration of PV in the planning and design of distribution systems may lead to inadequate resolutions of the other issues. For example, protection and safety issues may be considered based on present distribution system configurations and practices. But if, in fact, large local penetration of PV logically calls for basic changes in the distribution system, then protection and safety issues were considered for the wrong systems. The way in which some of the other issues might be resolved (such as harmonics, power factor related) could include changes in the distribution system. Such changes should be part of an early distribution system planning and design concepts effort. If not, then the conclusions will be suspect. Alternatives to the "one inverter, one home" concept (such as a shared inverter concept) would be included in a distribution system planning and design effort, as would alternatives to the arrangements for interconnection, control, etc., of PV units.

B. REFERENCES

1. Expansion Planning for Distribution Networks, ongoing DOE/EES contract with Carnegie Mellon University.

The task objective is to develop methods to plan the expansion of networks with conventional and emerging energy technologies including dispersed generation and storage devices.

A multi-objective model to optimize the operations of radial networks with dispersed storage and generation devices was developed. The optimization is in terms of two conflicting attributes: (1) operating cost and (2) load curtailment. The model is solved with a network version of the generalized transportation algorithm that uses multiple arcs between nodes and lower and upper bounding. A commercial code was implemented which solves large problems efficiently. The solution provides guidance for day-to-day operations. It can also be adapted to provide design and expansion information through sensitivity analyses of the configurations studied.

Models were also developed for predicting the effects of energy management technologies on two important system attributes: (1) production cost and, (2) the load shape seen by central generation. The models can include arbitrary mixes of central generation, dispersed generation, central storage, and dispersed storage.

2. Electric Power Distribution System Planning and Design with Dispersed Storage and Generation (DSG) and Distribution Automation and Control (DAC), RFP DEDS-19-01, by Oak Ridge National Lab for the Department of Energy.

The overall thrust of this activity is to carefully examine the distribution planning and design process in light of DAC and how DAC might facilitate the integration of DSG, and load management into the electric distribution system.

The specific tasks under this investigation are:

- (1) Perform conventional planning and design of a particular utility system after formulating a planning and design scenario.
- (2) Describe the modification in conventional distribution planning and design process required with DAC. Describe the DAC functions and why they are likely candidates for that particular system. Perform an analysis of the technical and economic impacts of DAC. The DAC functions to be considered are outage reporting, system reconfigurations, remote equipment operation, remote meter reading and VAR control.
- (3) Examine the changes in the planning and design process when DAC and load management are used, in addition to conventional distribution techniques, to help solve the scenario formulated earlier. The load management options to be considered are

customer thermal energy storage, direct and indirect control of customer loads, conservation and TOD rates, as they affect the distribution planning and design process.

- (4) Examine the changes in the distribution planning and design process when dispersed generation in low penetration exists on the utility system. Customer-owned and utility-owned dispersed generation will be considered separately and then compared. A low penetration is defined as two percent or less of the best utility system capacity under study unless reasons are shown that it should be otherwise.
- (5) The same as (4) but with a high penetration of DSG, DAC, and load management. A high penetration of dispersed generation is defined as between 10 and 20% unless reasons are shown that it should be otherwise.
- (6) The final task is to evaluate, compare, and summarize the cases studied to show the effectiveness of DAC, DAC and load management, and low and high penetrations of dispersed generation on distribution system short-term planning. Particular attention should be paid to the design criteria and problems faced by the utility such as line and equipment loadings, voltage control, harmonics, power factor, phase balance, losses, reliability, etc., if and where they apply. Distribution design guidelines should be provided for the following cases:
 - (a) Modified design with DAC.
 - (b) Modified design with DAC and load management.
 - (c) Modified design for low and high penetrations of dispersed generation.

3. Impacts of Dispersing Storage and Generation in Electric Distribution Systems, Final Report, System Control Inc. for the U.S. Department of Energy under Contract #EY-76-C-03-1214, July 1979.

The study objective was to determine the benefits, if any, of DSGs on utility distribution systems by reducing capacity requirements, increasing reliability, and lowering losses. Alternate DSG technologies studied include dispersed supply management devices placed on the utility side of the meter (such as solar energy generation, battery storage, and fuel cells) and use management devices placed on the customers side of the meters (such as cogeneration and storage space conditioning).

The methodology included detailed simulations of distribution system expansion planning with and without DSGs, using a consistent set of planning criteria. Models of alternate DSG operating controls were developed to satisfy distribution and/or bulk-supply system needs. The incremental effects

on the bulk-supply system production costs and capacity requirements were calculated. Detailed planning simulations in the methodology were used to model important distinct distribution system characteristics.

The overall study conclusions were:

- (1) To realize distribution capacity and reliability benefits, supply-side DSG may be operated in a manner departing from bulk-supply system economic dispatch principles. Potentially higher production costs and DSG capital costs may be incurred, in addition to increased backup bulk-supply capacity requirements for energy-limited, dispersed storage devices.
- (2) The overall cost benefits of DSG technologies are highly site-dependent. Substation placement is generally more favorable than placement along the circuits.
- (3) The overall benefit decreases over time with increasing dispersed utility-side storage. Total benefits improve over time with increased penetration of dispersed utility-side generation.
- (4) Utility-side dispersed generation tends to attain a greater overall benefit than dispersed storage.
- (5) The introduction of DSG into the electric distribution system will complicate present planning and operating practices. Present distribution practices relying on established planning guidelines and engineering judgment may prove insufficient because this experience was accumulated for systems without DSG. Planning and operation of DSG may require close coordination between bulk supply and distribution system planning.

Overall, the thrust of the study is an economic evaluation of DSGs rather than concern about how the planning problem will be modified by their inclusion. The study conclusion arrived at in (5) is precisely the issue that must be resolved for distributed PV systems.

4. Impact of Dispersed Solar and Wind Systems on
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Final Report by SCI for Oak Ridge National Lab,
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This study examined the technical and economic impacts of dispersing solar and wind (DSW) generation devices within the distribution system. A DSW operation model was developed to help determine the dependable capacity of fluctuating solar photovoltaic and wind generation as a part of the distribution planning process. Specific case studies using distribution system data and renewable resource data for Southern California Edison Company and Consumers Power Company were analyzed to gain insights into the effects of interconnecting DSW devices.

Although results were case-specific and applicable only to distribution systems studies, some important general conclusions are made. The DSW devices offered some distribution investment savings, depending on their availability during peak loads. For a summer-peaking utility, for example, dispersing photovoltaic systems are more likely to defer distribution capital investments than dispersing wind systems. Dispersing storage devices to increase DSW's dependable capacity for distribution system needs is not economically attractive. Spatial diversity among dispersed wind generators may improve their dependable capacity at the bulk generation level, but for the relatively small service area of a distribution system, this improvement is insignificant. Substation placement of DSW and storage devices is more cost-effective than feeder or customer placement.

C. GUIDELINES/STANDARDS

No guidelines or standards exist on this particular issue.

D. CONCLUSIONS

Many ongoing efforts are identified in the area of distribution planning and design with dispersed storage and generation including PV. All these efforts are sponsored by the DOE/EES. The results generated by these studies, once completed, would help resolve this particular issue. The impact of recent DOE budget changes on DOE/EES efforts is not yet known. It is quite probable that the expectations and plans will not be realized in full.

E. RECOMMENDATIONS

No recommendations for further work are provided at this time in the area of distribution planning and design. The "Shared Inverter" concept, however, must be explored further. It could have some ramifications in the planning and design of future distribution systems.

APPENDIX A

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APPENDIX B
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APPENDIX C
A SURVEY OF DISTRIBUTION PRACTICES
OF
TWO CALIFORNIA UTILITIES

SECTION I

PASADENA WATER AND POWER DEPARTMENT

A. INTRODUCTION

The utility of the city of Pasadena is representative of a small size urban system.

The majority of the electric power is locally produced in two generating stations: (1) Glenarm, completed in 1949, and, (2) Broadway, completed in 1965. The purchased power is channeled through the Goodrich receiving station, in operation since 1970.

Management of the system is accomplished through the dispatch center located close to the Glenarm generating station.

According to statistics, the power production for the fiscal year 1978-79 was 943,376,643 (kWh), up 5.1% from the previous year. Local generation increased by 21.4%, to 592,981,000 kWh, and accounted for 62.9% of total power production. Purchased power was imported from utilities in Washington, Oregon, Idaho, Montana, Nevada, Arizona, Southern California, and Canada and totaled 350,395,643 kWh, a 14.3% reduction from the prior year. The decline in purchased power was the result of moderate drought conditions throughout the pacific northwest thereby curtailing the availability of surplus hydroelectric power.

Twice during the 1978-79 fiscal year (September 26, 1978 and June 12, 1979) a new record peak of 193 MW was reached. This new record demand was 12 MW or 6.6% greater than the previous record which had occurred in June 1976. The population served was approximately 108,000 in a service area which covers 23.06 square miles. The average annual usage per residential customer was 4,808 kWh.

B. SYSTEM DESCRIPTION

The description of various elements of the power system is given below. The emphasis is on the distribution system.

1. Receiving Stations

This term describes the configuration at the location where the electrical energy is received, either from the power station generators or from the 220-kV Southern California Edison (SCE) grid.

Generation of power is performed at the level of 13.8 kV. Power is consequently transformed and fed into the high voltage, 17 kV and 34 kV, buses in the receiving stations. Each station is composed of two such buses operating in parallel.

The 17 kV bus power of one of the receiving stations is fed into the primary distribution feeders, delivering energy to commercial and industrial

customers. In the case of some essential loads, two 17-kV feeders are provided, each carrying half the load. In case of one feeder failing, the loads can be automatically thrown over to the other feeder, thus safeguarding continuity of service.

The 34-kV bus power of the other receiving stations is delivered to the area's distribution substations. Linkage to the neighboring utilities is also provided through the receiving stations.

2. Subtransmission Feeders

These are the 34-kV, 3-phase, 3-wire lines connecting the receiving stations with the distribution substations. With only a few exceptions, all of these lines are run underground. A 34-kV oil breaker is used for disconnecting the line from the receiving station bus.

3. Distribution Power Substation

There are ten strategically located, distribution substations within the service area; their complexity varies depending upon the capacity required. The basic configuration is shown in Figure C-1, with only one unit substation shown. The number of unit substations available at each station varies from one to three.

The 34-kV voltage is stepped down to the distribution level of 17 kV or 4 kV. The circuit breaker CB3 remains normally open, while CB1 and CB2 are normally closed. Each of the four feeders is installed on a different route. There are numerous cross connections among feeders throughout the system, but the switch positions are open, thus maintaining a radial system. The cross connections can be made at any time, however, either in case of trouble or in the process of reconfiguring the circuits in an area.

4. Distribution System Configuration

The term distribution system (DS) applies to the portion of the utility power system which starts at the distribution power substation and ends at the user's terminals. Normally little, if any, generation is performed within this system. The energy carried through the distribution system is delivered to residential, commercial, and industrial customers. In some cases, suburban and rural areas are also included.

The distribution system consists of primary and secondary circuits, lined by distribution transformers. The primary circuits are 3-phase, 4-wire, 4-kV and 3-phase, 3-wire, 17-kV. The increasing demand for power made the higher voltages desirable.

Distribution may be done by using overhead lines or underground cables. Urban areas favor the underground cables. In Pasadena, the primary distribution network consists of 4-kV and 17-kV feeders. As of July 1979, there were seven miles of 17-kV and 200 miles of 4-kV feeders stretched over 190 miles. The 4-kV primary feeder system covered 100 miles.

It should also be noted that the individual feeders are not more than two miles long. Each primary feeder can supply only a limited amount of energy. In the Pasadena system, the limits are 4 MVA for 4-kV and 14 MVA for 17-kV feeders. It is possible to modify the feeder configuration and transfer the customer to an alternative source of power when servicing the line. Four or five position load break oil switches are used for underground systems and single phase cutouts, called box switches, for overhead distribution.

The secondary distribution circuits supply power to residential customers at 120/240 V, 1-phase, 3-wire. Commercial and industrial customers are wired for 208Y/120-V, 3-phase, 4-wire or 480Y/277-V, 3-phase, 4-wire service.

For an overhead distribution, the step-down transformers are pole mounted. The underground system employs vault-type or subway-type transformers. The sizes of the residential type distribution transformers are 25 kVA for the older circuits, and 50 kVA for the newly wired installations. Larger size transformers may be used for supplying commercial and industrial customers. On the average, twelve residences are served by one distribution transformer.

5. Distribution System Protection

At the distribution substation (Figure C-1), the three circuit breakers CB1, CB2, and CB3 allow the load to be split between the north and south buses or feed the whole load from one single bus. Circuit breakers CB4 through CB7 protect the individual primary feeders. All the breakers are of the air type.

Protection of the two power transformers, TR1 and TR2, is accomplished by differential relays, which sense the current in the primary and secondary, and trip CB1 or CB2 in the case of current unbalance. Also, overcurrent relays at the source of the subtransmission feeders protect the transformers.

Multiple position oil switches SW1 and SW2 isolate the transformer primaries from the 34-kV bus. They can be opened under no-load only.

Each of the primary feeders starts at the terminals of the appropriate circuit breaker (CB4 through CB7). The 4-kV feeders are 4-wire, the 17-kV ones use 3 wires only.

The short-circuit protection of any individual phase of the primary feeder is achieved by using an overcurrent relay, that responds according to the time vs overcurrent curve. The ground relay on the fourth wire of the 4-kV system is provided to detect an excessive asymmetry of the line currents. The ground relay trips when the current reaches 50% of the line current. The circuit breakers tripped are CB4 through CB7. The circuit breakers used on the overhead primary feeders have an additional feature; a built-in capability of acting like the conventional reclosers do. They will try to restore service three times, automatically, before permanently locking out a sustained fault.

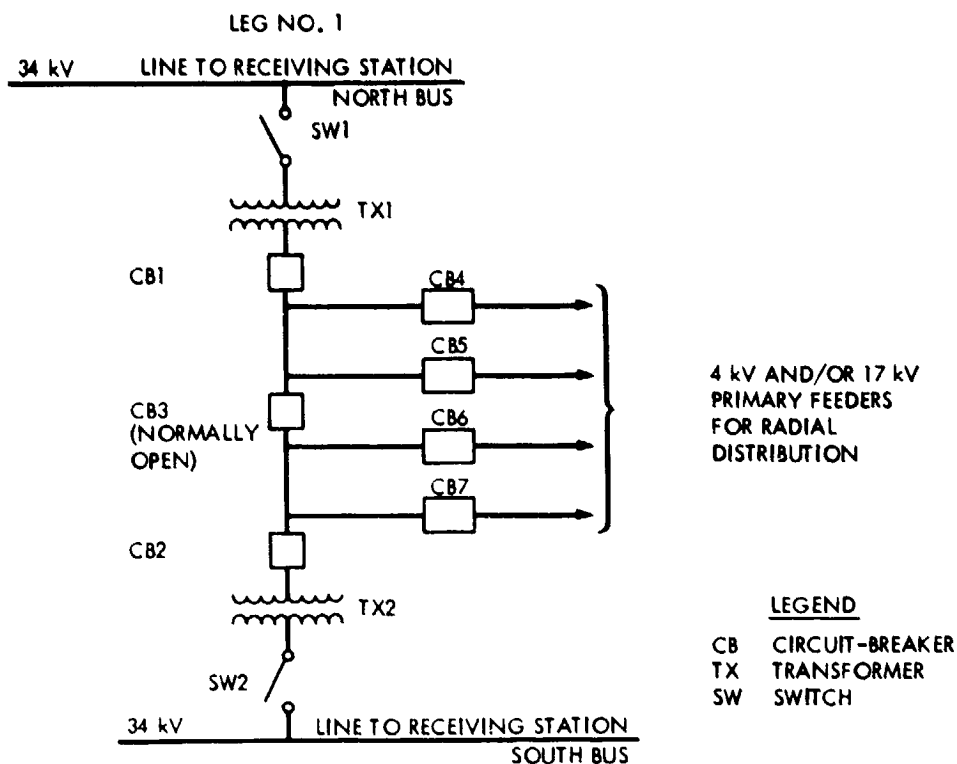


Figure C-1. Typical Distribution Substation: Single Leg with Four Primary Distribution Feeders

At each distribution substation one underfrequency relay monitors the distribution frequency. Shedding of the customer loads is initiated if the frequency drops under a predetermined critical value. Five levels of shedding are monitored, as shown in Table C-1.

Table C-1. Five Levels of Shedding

Level	1	2	3	4	5
Frequency (Hz)	59.1	58.9	58.7	58.5	58.2
Drop Load By ^a	10%	10%	10%	10%	Islanding

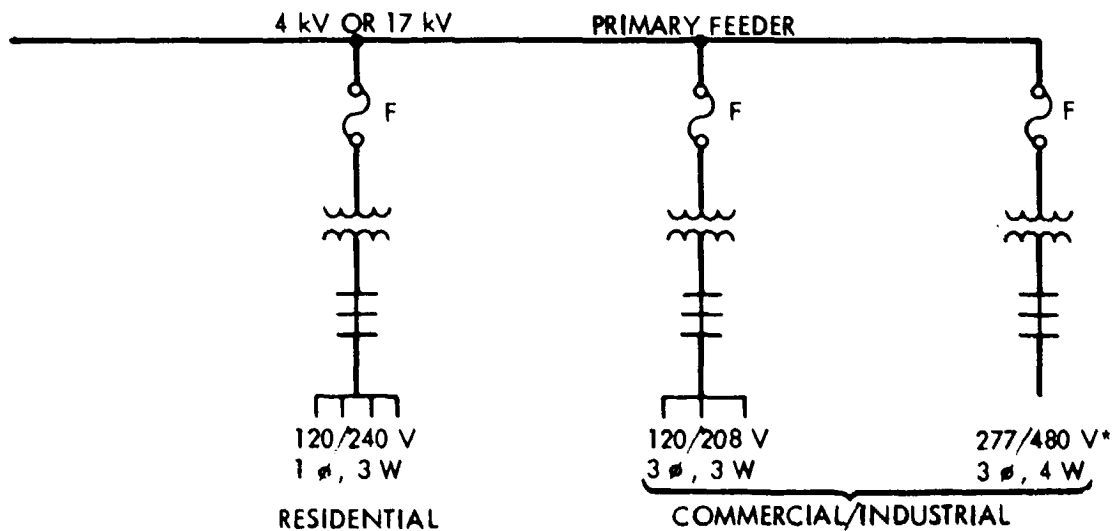
^aOf the total Pasadena consumption.
Only once has Pasadena experienced a Level 1 underfrequency trip.

The lateral, local branches (Figure C-2) channel the 4-kV or 17-kV power into the distribution transformers. These lateral feeders are three-phase or single-phase. Each lateral is terminated by a distribution transformer, reducing the voltage to the level of the secondary distribution. Each transformer is protected by a fuse (F). Expulsion-type fuses are used for overhead distribution; the 4-kV underground laterals are protected by oil fuse cut-outs; and the 17-kV underground lines use current-limiting fuses for the same purpose.

Little lightning protection is employed. As there is little lightning activity in the area, Pasadena will accept the loss of one or, at most, two distribution transformers every year rather than install costly surge arresters. Exceptions to the rule are protection of the underground cables by surge arresters installed at the points where the underground cable starts and ends.

6. Distribution System Voltage Control

Voltage control is achieved by an automatic adjustment of the primary transformer taps in the distribution substation (TR1 and TR2 in Figure C-1). The voltage at the midpoint of the primary feeder is used for reference feedback.



*USUALLY SUPPLIED FROM A SEPARATE FEEDER

Figure C-2. Various Types of Lateral Branches

In the past, the voltage at the customer terminals could fluctuate between 114V and 126V. Presently, with the idea of energy conservation the maximum permissible voltage at these terminals is 120V.

The transformer voltage is adjusted depending on the value of the load.

No line regulators are used in the Pasadena system.

7. Power Factor Control

Power factor correction is performed within the receiving stations by capacitor banks. Presently, five capacitor blocks, each rated at 10.8 MVAR, are installed within the system: two blocks in the Receiving Station D (34kV), one block at the Receiving Station B (17kV) and two at the Santa Anita Substation near Goodrich, (34kV). The dispatcher in the Dispatching Center adjusts, in steps, the amount of reactive power generated by remotely switching the individual blocks.

According to the existing policy:

- (1) No reactive power should be allowed to flow between the Pasadena and SCE systems.
- (2) Generation should run at 0.85 - 0.95 power factor.
- (3) Generation at a unity power factor or at a leading power factor should be avoided, as it could cause an unwanted system instability.

Some time ago fixed shunt capacitors were installed in various places on the 4kV primary feeders. They are now being phased out, as the Environmental Protection Agency has declared the PCB-dielectric potentially harmful to humans.

According to a directive issued by the Chief Engineer's office, no capacitors will be used in the future within the distribution system. Their use is not considered economically justifiable.

8. Metering and Rates

The residential customers are billed for kWh only. The commercial and industrial customer rate is a composite of kWh + kVAR + D₁₅ charges. The D₁₅ represents a 15-minute maximum kW demand; the higher D₁₅, the higher is the billing rate.

The value of the load powerfactor (PF) is determined from the kVARh meter reading. No charges are imposed if the PF remains between 0.75 and 0.85. A one percent penalty is imposed for each PF = 0.01 below PF = 0.75. A one-third percent credit is granted for each PF = 0.01 above PF = 0.85.

SECTION II

SOUTHERN CALIFORNIA EDISON

A. INTRODUCTION

The SCE utility represents a large size system. The important 1980 statistical data are shown below:

- (1) Service area: 50,000 square miles.
- (2) Peak demand: 12,612 MW as recorded on 7/30/80 at 3:00 p.m.
- (3) Overhead circuits: total circuits; 3,602 and, total circuit miles; 61,500 miles.
- (4) Underground circuits: duct miles; 7,752 miles.
- (5) Distribution transformers
 - (a) Overhead: 440,807 units
12,574 MVA capacity
 - (b) Underground: 93,160 units
11,197 MVA capacity
- (6) Meters: 3,207,594 units
- (7) Capacitors (installed on distribution circuits)
 - (a) No. of Banks: 9,451
 - (b) Total MVAR: 5,900

B. SYSTEM DESCRIPTION

The distribution system consists of primary and secondary circuits.

1. Primary Distribution

The primary circuits consist of the primary, radially arranged feeders, and the primary lateral circuits. The majority of primary distribution is performed at 4 kV, 7 kV, 12 kV, or 16 kV, all three-phase.

As indicated above, the majority of the primary distribution is overhead. All primary feeders are three-phase. Typically, they are loaded to approximately 500A line current, which for a three-phase 12-kV line corresponds to 10.4 MW loading. The primary laterals are single or three-phase.

The primary circuits are reconfigured daily by means of three-phase air operated disconnect switches for an overhead system and multi-position load break oil switches for an underground distribution system. Reconfiguration is implemented by the service personnel on site; no remote control is available.

2. Distribution Transformers

The distribution transformer provides the necessary link between the primary and the secondary system. Single-phase transformers are used, thus two or three transformers must be installed for three-phase service. Although the size, weight, and cost of such a configuration is higher, the cost of storage of the spares and the cost of replacement appear to predominate and be a driving force for this policy.

Sizes of the residential units vary from 15 kVA to 100 kVA for an overhead distribution. The underground residential services uses 25-, 50-, 75-, and 100-kVA sizes. The power handling capacity of the industrial and commercial three-phase configuration can vary from 75 kVA to the 3750-kVA level. The agricultural three-phase transformer banks rate from 15 kVA to 500 kVA.

Pole-, pad-, vault-, or hole-type transformers are used. Transformer oil is used for insulation and cooling. Transformers used in the vaults and holes are sealed and may be operated under water.

The primary side of each transformer is protected by a fuse.

3. Secondary Distribution

Secondary distribution originates at the secondary side of the distribution transformer and terminates at the customer's terminals.

The following groups of customers can be identified:

Customer	% Share	Type Service
Residential	30	1-phase, 3-Wire (W), 120/240 V
Commercial	30	3-phase ^a
Industrial	30	3-phase ^a
Agricultural	10	3-phase, 480 V, 3-Wire.

^aSecondary voltages: 240 V, 3 ph, 3 W; 480 V, 3 ph, 3 W; 120/240 V, 3 ph, 4 W; 240/480 V, 3 ph, 4 W open Δ ; 120/208 V, 3 ph, 4 W, Y; 277/480 V, 3 ph, 4 W, Y.

On the average, nine residential customers are connected to the transformer's secondary. As many as thirty may be connected if the service capacity is low, i.e., for people living in condos. The SCE estimate for an all-electric home in Palm Springs is 10 kVA per home; an equivalent home on the beach, without air-conditioning, requires only 1.2 kVA.

4. Voltage Reduction Savings

By limiting the maximum secondary voltage to 120 V rather than to 126 V within the residential and commercial distribution circuits, 1,618 GWh were saved in 1980, according to SCE statistics. This is a savings equivalent to 2.78 million barrels of oil.

It should also be noted that the industrial and agricultural customers are not included in this policy. Their maximum voltage level remains unchanged, at 126 V.

5. Distribution System Protection

It is the customers' responsibility to protect the low voltage circuit within his premises by supplying, on his premises, a breaker or fuse panel for overcurrent protection.

Short-circuits within the secondary distribution, beyond reach of domestic protection, are cleared by the fuses on the primary side of the distribution transformer.

Overcurrent protection of the primary circuits is provided by automatic reclosers and substation circuit breakers (Figure C-3).

The majority of the automatic reclosers are provided in high fire hazard areas on the lateral lines for protection against short circuits.

Phase and ground relays trip the substation circuit breakers CB1 and/or CB2 (Figure C-3) in case of a sustained fault that was not cleared by the individual fuse (Figure C-2).

All the single phase underground lateral branches (UG in Figure C-3) are fuse-protected at the entry point. On the three-phase entries, loadbreak switches are employed instead of fuses.

No additional line reactors are used to limit the magnitude of the short-circuit current, as the leakage reactance of the substation transformers suffices.

Lightning arresters are used selectively in territories of high lightning activity. In the substations, lightning arresters are used for safeguarding the transformers and primary buses.

On the primary overhead distribution, lightning arresters are used selectively to protect distribution transformers, capacitor banks, reclosers, sectionalizers, and underground entries.

6. Distribution System Voltage Control

It should be recognized that the major part of overall system voltage control is accomplished in the subtransmission power stations that feed the individual local substations. Only a minor variation of the voltage is allowed at the output busses of the individual substation.

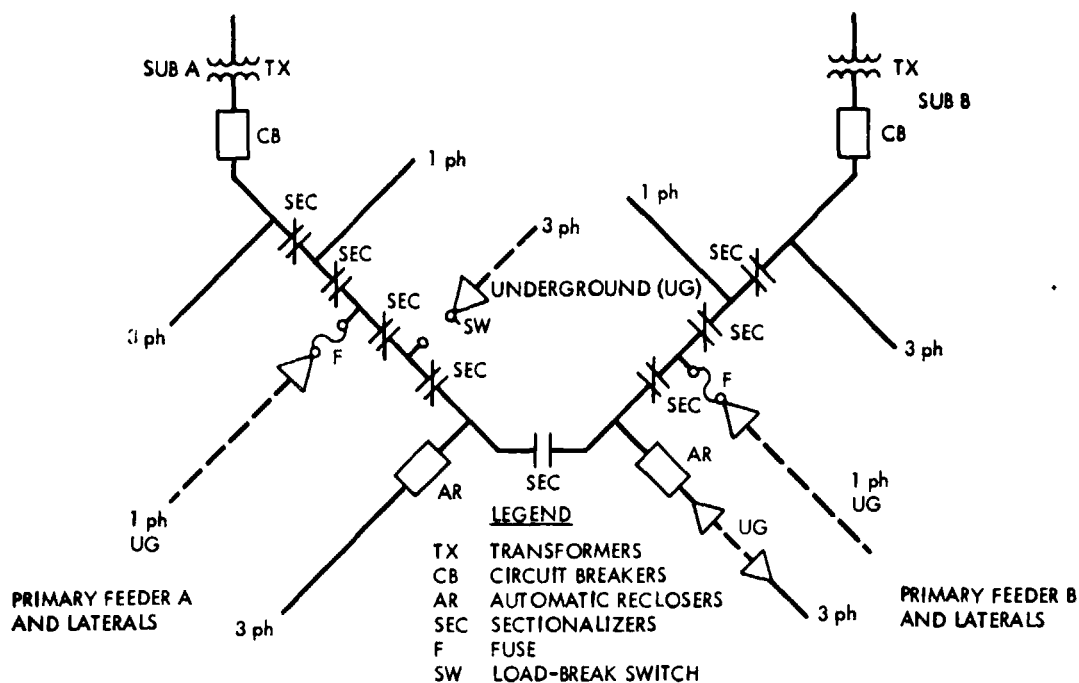


Figure C-3. Primary Distribution

Line capacitors on the overhead primary distribution network maintain the secondary voltage within the 114-V to 120-V (or 126 V) limits.

A fixed portion of the capacitor bank compensates for the minimum load conditions. The remaining portion is switched by a voltage-sensitive relay.

The voltage value at which the capacitors are switched-on is biased according to a time schedule. The timing satisfies an anticipated kVA requirement for keeping the power factor near unity.

No capacitors are used underground because no submersible switches are available so far. The capacitors used are oil filled. The use of PCB-dielectric is phased out.

7. Metering

The residential customers are billed for kWh only. The commercial and industrial customers are billed according to the maximum demand. They may additionally pay for the kVARh, should the load they use have low power-factor characteristics.

8. Harmonics

Some users are monitored as to the level of harmonics they generate and, in case of complaints, are responsible for suppressing them at their own expense.

9. Power Factor

The Company may require the customer to provide, at his own expense, equipment to increase the operating power factor of each complete unit of neon, fluorescent, or other gaseous tube lighting equipment to not less than 90%, lagging or leading.

10. Interference with Service

SCE strictly enforces the PCU's rule No. 2 which states that:

- (1) Customers who operate equipment which causes detrimental voltage fluctuations (such as, but not limited to, hoists, welders, radio transmitters, X-ray apparatus, elevator motors, compressors, and furnaces) must reasonably limit such fluctuations upon request by the Company. The customer will be required to pay for whatever corrective measures are necessary.
- (2) Prior to the installation of any new arc furnace, or design modification of an existing furnace, the customer shall provide basic design information for the installation to aid the Company in determining the method of service and the allowable level of load fluctuations.
- (3) Any customer who superimposes a current of any frequency upon any part of his electrical system, other than the current supplied by the Company, shall, at his expense, prevent the transmission of such current beyond his electrical system.

11. Safety

Present guidelines for servicing any part of the distribution system state that all power sources must be disconnected from the line before they can be worked on. This also applies in the case of cogeneration.

APPENDIX D

**LIST OF ORGANIZATIONS INVOLVED IN
UTILITY INTERFACE ACTIVITIES**

- (1) State Public Utility Commissions, e.g., State of California, etc.
- (2) American National Standard Institute, e.g., Steering Committee on Solar Energy Standards Development.
- (3) Institute of Electrical and Electronic Engineers (IEEE).
 - (a) Power Engineering Society
 - 1) Working group to investigate consumer-owned sources of generation 1000 kVA or less.
 - 2) Working group on harmonics.
 - 3) Working group on lightning protection of distribution lines.
 - 4) Task group on long-range distribution planning.
 - 5) Working group on long-range system planning.
 - 6) Working group to study wave distortions in consumers interconnections.
 - 7) Working group on AC-DC converter station harmonics.
 - 8) Working group to study effect of harmonics on meters.
 - (b) Industry Application Society
 - 1) Harmonics and reactive compensation subcommittee.
 - 2) Thyristor Converters for Motor Drives - Packaged Drive Standards Subcommittee.
 - 3) Wave Shape Distortion Working Group.
 - (c) Standards Coordination Committee on Photovoltaics
 - 1) Photovoltaics System Subcommittee on Standards for Terrestrial Photovoltaic Systems-Utility Interface Working Group.
 - 2) Photovoltaics Array Subcommittee.
 - 3) Photovoltaics Power Conditioning Subcommittee.
 - 4) Photovoltaic Storage Subcommittee.
- (4) Department of Energy (DOE) including Division of Electric Energy Systems (EES).

- (5) Electric Power Research Institute (EPRI).
- (6) American Public Power Association (APPA).
- (7) National Rural Electric Cooperative Association (NRECA).
- (8) Underwriters Laboratory (UL).